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4.1 SUMMARY DESCRIPTION

This section was prepared using the licensing topical report, "General Electric Standard Application for Reactor Fuel" (GESTAR II) Reference 4.1-1, GESTAR II compliance documents (References 4.1-4 and 4.1-5), the cycle-specific design report (Reference 4.1-2) and the "Fuel Bundle Information Report" (Reference 4.1-3).

The reactor assembly consists of the reactor vessel, internal components of the core, shroud, steam separator and dryer assemblies, and jet pumps. Also included in the reactor assembly are the control rods, control rod drive housings, and the control rod drives. Figure 5.3-5 shows the arrangement of reactor assembly components. A summary of the important design and performance characteristics is given in Section 1.3. Loading conditions for reactor assembly components are specified in Section 3.9. The core load varies for each cycle and is shown in Reference 4.1-2.

4.1.1 REACTOR VESSEL

The reactor vessel design and description are discussed in Section 5.3.

4.1.2 REACTOR INTERNAL COMPONENTS

The major reactor internal components are the core (fuel, channels, control blades, and instrumentation), the core support structure (including the shroud, top guide and core plate), the shroud head and steam separator assembly, the steam dryer assembly, the feedwater spargers, the core spray spargers, and the jet pumps. Except for the Zircaloy and NSF (Niobium-Sn-Fe) in the reactor core, these reactor internals are stainless steel or other corrosion resistant alloys. All major internal components of the vessel can be removed except the jet pump diffusers, the jet pump risers, the shroud, the core spray lines, spargers, and the feedwater sparger. The removal of the steam dryers, shroud head and steam separators, fuel assemblies, in-core assemblies, control rods, orificed fuel supports, and control rod guide tubes can be accomplished on a routine basis.

4.1.2.1 Reactor Core

4.1.2.1.1 General

The reactor core is composed of fuel assemblies manufactured by Global Nuclear Fuel (GNF).

A number of important features of the BWR core design are summarized in the following paragraphs:

a. The BWR core mechanical design is based on conservative application of stress limits, operating experience, and experimental test results. The moderate pressure levels characteristics of a direct cycle reactor (approximately 1035 psia) result in moderate cladding temperatures and stress levels;

b. The low coolant saturation temperature, high heat transfer coefficients, and neutral water chemistry of the BWR are significant, advantageous factors in minimizing Zircaloy temperature and associated temperature-dependent corrosion and hydride buildup;

   The relatively uniform fuel cladding temperatures throughout the core minimize migration of the hydrides to cold cladding zones and reduce thermal stresses;

c. The basic thermal and mechanical criteria applied in the design have been proven by irradiation of statistically significant quantities of fuel. The design heat transfer rates and linear heat generation rates are similar to values proven in fuel assembly irradiation;

d. The design power distribution used in sizing the core represents a worst expected state of operation;

e. The thermal margin analyses ensure that more than 99.9% of the fuel rods in the core are expected to avoid boiling transition for the most severe anticipated operational occurrences described in Chapter 15. The possibility of boiling transition occurring during normal reactor operation is insignificant; and

f. Because of the large negative moderator density coefficient of reactivity, the BWR has a number of inherent advantages. These are the uses of coolant flow for load following, the inherent self-flattening of the radial power distribution, the ease of control, the spatial xenon stability, and the ability to override xenon to follow load.

Boiling water reactors do not usually have instability problems due to xenon. This has been demonstrated by special tests which were conducted on operating BWRs and by calculations. Xenon transients are highly damped in a BWR due to the large negative power coefficient of reactivity (Reference 4.1-7).

Columbia Generating Station (CGS) has installed a stability detect and suppress system to ensure hydrodynamic stability while operating in regions susceptible to instability. Stability system limits are specified in the Technical Specifications and in the Core Operating Limits Report.

Important features of the reactor core arrangement are as follows:

a. The original bottom-entry cruciform control rods consist of B_4C in stainless steel tubes surrounded by a stainless steel sheath;

b. The bottom-entry cruciform Duralife 215 control rods consist of 18 high-purity stainless steel tubes at each wing filled with boron-carbide and three hafnium rods at the edge of each wing and a hafnium plate at the top;

c. The bottom-entry cruciform Marathon control rods consist of 17 high-purity stainless steel tubes in each wing. Eleven of the tubes are filled with boron-carbide, two of the tubes are partially filled with boron-carbide and four tubes are filled with hafnium rods (three at the outer edge of each wing and one at the center of the wing). See Figure 4.2-1.5 for details;

d. The in-core location of the startup and power range instruments provides coverage of the large reactor core and provides an acceptable signal-to-noise ratio and neutron-to-gamma ratio. All in-core instrument leads enter from the bottom and the instruments are in service during refueling. In-core instrumentation is further discussed in Sections 7.6.1.4 and 7.7.1.6;

e. As shown by experience obtained at other plants, the operator, utilizing the in-core flux monitor system, can maintain the desired power distribution within a large core by proper control rod scheduling;

f. The Zircaloy-4 and NSF channels provide a fixed flow path for the boiling coolant, serve as a guiding surface for the control rods, and protect the fuel during handling operations;

g. The mechanical reactivity control permits criticality checks during refueling and provides maximum plant safety. The core is designed to be subcritical at any time in its operating history with any one control rod fully withdrawn; and

h. The selected control rod pitch represents a practical value of individual control rod reactivity worth and allows ample clearance below the pressure vessel between control rod drive mechanisms for ease of maintenance and removal.

4.1.2.1.2 Core Configuration

The reactor core is arranged as an upright circular cylinder containing a large number of fuel cells and is located within the reactor vessel. The coolant flows upward through the core. The BWR core is composed of essentially two components: fuel assemblies and control rods. The General Electric Company (GE) control rod mechanical configuration (see Figure 4.2-1) is basically the same as used in all GE BWRs.

4.1.2.1.3 Fuel Assembly Description

The GNF reload fuel assemblies are GNF2 (Reference 4.1-4) and GE14 (Reference 4.1-5).

4.1.2.1.3.1 Fuel Rod. A fuel rod consists of UO_2 pellets and a Zircaloy-2 cladding tube. A fuel rod is made by stacking pellets into a Zircaloy-2 cladding tube, which is sealed by welding Zircaloy end plugs in each end of the tube. The GNF fuel rods are pressurized to 10 atmospheres (References 4.1-4 and 4.1-5).

The BWR fuel rod is designed as a pressure vessel. The ASME Boiler and Pressure Vessel (B&PV) Code, Section III, is used as a guide in the mechanical design and stress analysis of the fuel rod.

The rod is designed to withstand the applied loads, both external and internal. The fuel pellet is sized to provide sufficient volume within the fuel tube to accommodate differential expansion between fuel and clad. Overall fuel rod design is conservative in its accommodation of the mechanisms affecting fuel in a BWR environment. Fuel rod design bases are discussed in more detail in Section 4.2.1.

4.1.2.1.3.2 Fuel Bundle. The fuel bundle has two important design features:

a. The bundle design places minimum external forces on a fuel rod; each fuel rod is free to expand in the axial direction, and

b. The unique structural design permits the removal and replacement, if required, of individual fuel rods.

The fuel bundles are designed to meet all the criteria for core performance and to provide ease of handling. Selected fuel rods in each bundle differ from the others in uranium enrichment. This arrangement produces more uniform power production across the fuel bundle and thus allows a significant reduction in the amount of heat transfer surface required to satisfy the design thermal limitations.

The GNF reload bundle contains 92 fuel rods and 2 large central water rods, all in a 10 x 10 array.

4.1.2.1.4 Assembly Support and Control Rod Location

Some peripheral fuel assemblies are supported by the core plate. Otherwise, individual fuel assemblies in the core rest on fuel support pieces mounted on top of the control rod guide tubes. Each guide tube, with its fuel support piece, bears the weight of four assemblies and is supported by a control rod drive penetration nozzle in the bottom head of the reactor vessel. The core plate provides lateral support and guidance at the top of each control rod guide tube.

The top guide, mounted inside the shroud, provides lateral support and guidance for each fuel assembly. The reactivity of the core is controlled by cruciform control rods and their associated mechanical hydraulic drive system. The control rods occupy alternate spaces between fuel assemblies. Each independent drive enters the core from the bottom and can accurately position its associated control rod during normal operation and yet insert the control rod in less than 7 sec during the scram mode of operation. Bottom entry allows optimum power shaping in the core, ease of refueling, and convenient drive maintenance.

4.1.2.2 Shroud

The shroud is a cylindrical, stainless-steel structure which surrounds the core and provides a barrier to separate the upward flow through the core from the downward flow in the annulus and also provides a floodable volume in the unlikely event of an accident which would otherwise drain the reactor pressure vessel. A flange at the top of the shroud mates with a flange on the shroud head and steam separators. The upper cylindrical wall of the shroud and the shroud head form the core discharge plenum. The jet pump discharge diffusers penetrate the shroud support below the core elevation to introduce the coolant to the inlet plenum. To prevent direct flow from the inlet to the outlet nozzles of the recirculation loops, the shroud support is welded to the vessel wall. The shroud support is designed to support and locate the jet pumps, core support structure, and some peripheral fuel assemblies.

Mounted inside the upper shroud cylinder in the space between the top of the core and the upper shroud flange are the core spray spargers with spray nozzles for injection of cooling

water. The core spray spargers and nozzles do not interfere with the installation or removal of fuel from the core.

4.1.2.3 Shroud Head and Steam Separators

The shroud head consists of a flange and dome onto which is welded an array of standpipes, with a steam separator located at the top of each standpipe. The shroud head mounts on the flange at the top of the cylinder and forms the cover of the core discharge plenum region. The joint between the shroud head and shroud flange does not require a gasket or other replacement sealing technique. The fixed axial flow type steam separators have no moving parts and are made of stainless steel.

In each separator, the steam-water mixture rising from the standpipe impinges on vanes which give the mixture a spin to establish a vortex wherein the centrifugal forces separate the steam from the water. Steam leaves the separator at the top and passes into the wet steam plenum below the dryer. The separated water exits from the lower end of the separator and enters the pool that surrounds the standpipes to enter the downcomer annulus. An internal steam separator diagram is shown in Figure 4.1-1.

For ease of removal, the shroud head is bolted to the shroud top flange by long shroud head bolts that extend above the separators for easy access during refueling. The shroud head is guided into position on the shroud via guide rods on the inside of the vessel and locating pins located on the shroud head. The objective of the shroud head bolt design is to provide direct access to the bolts during reactor refueling operations with minimum-depth underwater tool manipulation during the removal and installation of the assemblies.

4.1.2.4 Steam Dryer Assembly

The steam dryer assembly is mounted in the reactor vessel above the shroud head and forms the top and sides of the wet steam plenum. Vertical guide rods on the inside of the vessel provide alignment for the dryer assembly during installation. The dryer assembly is supported by pads extending from the vessel wall and is locked into position during operation by the reactor vessel top head. Steam from the separators flows upward into the dryer assembly. The steam leaving the top of the dryer assembly flows into vessel steam outlet nozzles which are located alongside the steam dryer assembly. Moisture is removed by the dryer vanes and flows first through a system of troughs and pipes to the pool surrounding the separators and then into the downcomer annulus between the core shroud and reactor vessel wall. The diagram of a typical steam dryer panel is shown in Figure 4.1-2.

4.1.3 REACTIVITY CONTROL SYSTEMS

4.1.3.1 Operation

The control rods perform dual functions of power distribution shaping and reactivity control. Power distribution in the core is controlled during operation of the reactor by manipulation of selected patterns of rods. The rods, which enter from the bottom of the near-cylindrical reactor core, are positioned in such a manner to counter-balance steam voids in the top of the core and effect significant power flattening.

These groups of control elements, used for power flattening, experience a somewhat higher duty cycle and neutron exposure than the other rods in the control system.

The reactivity control function requires that all rods be available for either reactor "scram" (prompt shutdown) or reactivity regulation. Because of this, the control elements are mechanically designed to withstand the dynamic forces resulting from a scram. They are connected to bottom-mounted, hydraulically actuated drive mechanisms which allow either axial positioning for reactivity regulation or rapid scram insertion. The design of the rod-to-drive connection permits each blade to be attached or detached from its drive without disturbing the remainder of the control system. The bottom-mounted drives permit the entire control system to be left intact and operable for tests with the reactor vessel open.

4.1.3.2 Description of Rods

The cruciform shaped control rods contain 76 stainless steel tubes (19 tubes in each wing of the cruciform) filled with vibration compacted boron-carbide powder. The tubes are seal welded with end plugs on either end. Stainless steel balls are used to separate the tubes into individual compartments. The stainless steel balls are held in position by a slight crimp in the tube. The individual tubes act as pressure vessels to contain the helium gas released by the boron-neutron capture reaction.

The tubes are held in a cruciform array by a stainless steel sheath extending the full length of the tubes. A top handle, shown in Figure 4.2-1, aligns the tubes and provides structural rigidity at the top of the control rod. Rollers, housed in the handle, provide guidance for control rod insertion and withdrawal. A bottom casting is also used to provide structural rigidity and contains positioning rollers and a parachute-shaped velocity limiter. The handle and lower casting are welded into a single structure by means of a small cruciform post located in the center of the control rod. A steel stiffener is located approximately at the midspan of each cruciform wing. The control rods can be positioned at 6-in. steps and have a nominal withdrawal and insertion speed of 3 in./sec.

The foregoing description of the control rods applies to the design of the original control rods. There have been two different replacement control rods used, Duralife 215 and Marathon

control rods. These replacement rods have design changes that increase the neutron absorption and make other material property improvements. The newer control rods are similar to and are fully interchangeable with the original control rod assemblies and are compatible with the existing nuclear steam supply system hardware.

The Duralife 215 control rods differ from the previous control rods in that a hafnium absorber plate is used at the top of each cruciform section, hafnium absorber rods replace several of the boron carbide absorber rods on the periphery of each cruciform section, and the stainless steel stiffener is removed from each wing. There are 21 absorber rods in each wing, of which 18 are stainless-steel tubes containing boron carbide and three are hafnium rods. The outside diameter remains the same. The length of the absorber column in these rods has been reduced from 143 in. to 137 in. to accommodate the top 6-in.-high hafnium plate. The increased volume of neutron absorber material increases the relative reactivity worth in the cold condition and increases the nuclear lifetime.

The Marathon control rod blades are an improved version of the Duralife 215 control blades and have the absorber and sheath arrangement replaced with an array of square tubes, which results in reduced weight and increased absorber volume. The square tubes each have four lobes to allow adjacent tubes to be welded to each other. The absorber tubes are welded lengthwise to form the four wings of the control rod. Each wing is comprised of 17 absorber tubes. The absorber tubes each act as an individual pressure chamber for the retention of helium. The region between each pair of square tubes is filled with helium and sealed top and bottom by welding. The four wings are then welded to the tie rod to form the cruciform-shaped member of the control rod. The Marathon control rod blade has the full-length tie rod replaced with a segmented tie rod, which also reduces weight.

The square tubes are circular inside and are loaded with either B_4C or hafnium. The B_4C is contained in separate capsules to prevent its migration. The capsules are placed inside the square absorber tubes and are smaller than the absorber tube inside diameter, allowing the B_4C to swell before making contact with the absorber tubes thereby increasing stress corrosion resistance. Empty tubes may be used adjacent to the tie rods to achieve the desired reactivity worth. The combination of absorbers and absorber tubes is based on the needed initial reactivity worth. In addition, empty capsules are used in some absorber tubes to provide a plenum for helium released during B_4C burnup.

The velocity limiter, shown in Figure 4.2-2, is a device which is an integral part of the control rod and protects against the low probability of a rod drop accident. It is designed to limit the free fall velocity and reactivity insertion rate of a control rod so that minimum fuel damage would occur. It is a one-way device, in that control rod scram time is not significantly affected.

Control rods are cooled by the core leakage (bypass) flow. The core leakage flow is made of recirculation flow that leaks through the several leakage flow paths, which are as follows:

a. The area between fuel channel and fuel assembly nosepiece,

b. The area between fuel assembly nosepiece and fuel support piece,

c. Holes in the lower tie plate,

d. The area between fuel support piece and core plate,

e. The area between core plate and shroud,

f. Holes in the core plate near power range monitor instrument guide tubes,

g. Various leakage paths around the control rod guide tubes, and

h. Control rod drive cooling water.

4.1.3.3 Supplementary Reactivity Control

Supplemental reactivity control is achieved with burnable poison. The supplementary burnable poison is gadolinia (Gd_2O_3) mixed with UO_2 in selected fuel rods in each fuel bundle.

4.1.4 ANALYSIS TECHNIQUES

4.1.4.1 Reactor Internal Components

Computer codes used for the analysis of the internal components as a basis for the original operating license are listed as follows:

a. MASS
b. SNAP (MULTISHELL)
c. GASP
d. NOHEAT
e. FINITE
f. DYSEA
g. SHELL 5
h. HEATER
i. FAP-71
j. CREEP-PLAST

The following italicized detailed descriptions of these programs are historical and were provided to support the application for an operating license.

4.1.4.1.1 MASS (Mechanical Analysis of Space Structure)

4.1.4.1.1.1 Program Description. This is a proprietary program of GE and is an outgrowth of the PAPA (Plate and Panel Analysis) program originally developed by L. Beitch in the early 1960s. The program is based on the principle of the finite element method. Governing matrix equations are formed in terms of joint displacements using a "stiffness-influence-coefficient" concept originally proposed by L. Beitch (Reference 4.1-9). The program offers curved beam, plate, and shell elements. It can handle mechanical and thermal loads in a static analysis and predict natural frequencies and mode shapes in a dynamic analysis.

4.1.4.1.1.2 Program Version and Computer. The Nuclear Energy Division is using a past revision of MASS. This revision is identified as revision "0" in the computer production library. The program operates on the Honeywell 6000 computer.

4.1.4.1.1.3 History of Use. Since its development in the early 1960s, the program has been successfully applied to a wide variety of jet-engine structural problems, many of which involve extremely complex geometries. The use of the program in the Nuclear Energy Division also started shortly after its development.

4.1.4.1.1.4 Extent of Application. Besides the Jet Engine and Nuclear Energy Divisions, the Missile and Space Division, the Appliance Division, and the Turbine Division of GE have also applied the program to a wide range of engineering problems. The Nuclear Energy Division uses it mainly for piping and reactor internals analyses.

4.1.4.1.2 SNAP (MULTISHELL)

4.1.4.1.2.1 Program Description. The SNAP Program, which is also called MULTISHELL, is the GE code which determines the loads, deformations, and stresses of axisymmetric shells of revolution (cylinders, cones, discs, toroids, and rings) for axisymmetric thermal boundary and surface load conditions. Thin shell theory is inherent in the solution of E. Peissner's differential equations for each shell's influence coefficients. Surface loading capability includes pressure, average temperature, and liner through wall temperature gradients; the latter two may be linearly varied over the shell meridian. The theoretical limitations of this program are the same as those of classical theory.

4.1.4.1.2.2 Program Version and Computer. The current version maintained by the GE Jet Engine Division at Evandale, Ohio, is being used on the Honeywell 6000 computer in GE/NED.

4.1.4.1.2.3 History of Use. The initial version of the Shell Analysis Program was completed by the Jet Engine Division in 1961. Since then, a considerable amount of modification and addition has been made to accommodate its broadening area of application. Its application in the Nuclear Energy Division has a history longer than 10 years.

4.1.4.1.2.4 Extent of Application. The program has been used to analyze jet engine, space vehicle and nuclear reactor components. Because of its efficiency and economy, in addition to reliability, it has been one of the main shell analysis programs in the Nuclear Energy Division of GE.

4.1.4.1.3 GASP

4.1.4.1.3.1 Program Description. GASP is a finite element program for the stress analysis of axisymmetric or plane two-dimensional geometries. The element representations can be either quadrilateral or triangular. Axisymmetric or plane structural loads can be input at nodal points. Displacements, temperatures, pressure loads, and axial inertia can be accommodated. Effective plastic stress and strain distributions can be calculated using a bilinear stress-strain relationship by means of an iterative convergence procedure.

4.1.4.1.3.2 Program Version and Computer. The GE version, originally from the developer, Professor E. L. Wilson, operates on the Honeywell 6000 computer.

4.1.4.1.3.3 History of Use. The program was developed by Professor E. L. Wilson in 1965 (Reference 4.1-10). The present version in GE/NED has been in operation since 1967.

4.1.4.1.3.4 Extent of Application. The application of GASP in GE/NED is mainly for elastic analysis of axisymmetric and plane structures under thermal and pressure loads. The GE version has been extensively tested and used by engineers in the company.

4.1.4.1.4 NOHEAT

4.1.4.1.4.1 Program Description. The NOHEAT program is a two-dimensional and axisymmetric transient nonlinear temperature analysis program. An unconditionally stable numerical integration scheme is combined with iteration procedure to compute temperature distribution within the body subjected to arbitrary time- and temperature-dependent boundary conditions.

This program utilizes the finite element method. Included in the analysis are the three basic forms of heat transfer, conduction, radiation, and convection, as well as internal heat generation. In addition, cooling pipe boundary conditions are also treated. The output includes temperature histories of all the nodal points established by the user. The program can handle multitransient temperature input.

4.1.4.1.4.2 Program Version and Computer. The current version of the program is an improvement of the program originally developed by I. Farhoomand and Professor E. L. Wilson of University of California at Berkeley (Reference 4.1-11). The program operates on the Honeywell 6000 computer.

4.1.4.1.4.3 History of Use. The program was developed in 1971 and installed in GE Honeywell computer by one of its original developers, I. Farhoomand, in 1972. A number of heat transfer problems related to the reactor pedestal have been satisfactorily solved using the program.

4.1.4.1.4.4 Extent of Application. The program using finite element formulation is compatible with the finite element stress-analysis computer program GASP. Such compatibility simplified the connection of the two analyses and minimizes human error.

4.1.4.1.5 FINITE

4.1.4.1.5.1 Program Description. FINITE is a general-purpose finite element computer program for elastic stress analysis of two-dimensional structural problems including (1) plane stress, (2) plane strain, and (3) axisymmetric structures. It has provisions for thermal, mechanical, and body force loads. The materials of the structure may be homogeneous or inhomogeneous and isotropic or orthotropic. The development of the FINITE program is based on the GASP program (see Section 4.1.4.1.3).

4.1.4.1.5.2 Program Version and Computer. The present version of the program at GE/NED was obtained from the developer J. E. McConnelee of GE/Gas Turbine Department in 1969 (Reference 4.1-12). The NED version is used on the Honeywell 6000 computer.

4.1.4.1.5.3 History of Use. Since its completion in 1969, the program has been widely used in the Gas Turbine and the Jet Engine Departments of the GE for the analysis of turbine components.

4.1.4.1.5.4 Extent of Use. The program is used at GE/NED in the analysis of axisymmetric or nearly-axisymmetric BWR internals.

4.1.4.1.6 DYSEA

4.1.4.1.6.1 Program Description. The DYSEA (Dynamic and Seismic Analysis) program is a GE proprietary program developed specifically for seismic and dynamic analysis of RPV and internals/building system. It calculates the dynamic response of linear structural system by either temporal modal superposition or response spectrum method. Fluid-structure interaction effect in the RPV is taken into account by way of hydrodynamic mass.

Program DYSEA was based on program SAPIV with added capability to handle the hydrodynamic mass effect. Structural stiffness and mass matrices are formulated similar to SAPIV. Solution is obtained in time domain by calculating the dynamic response mode-by-mode. Time integration is performed by using Newmark's β-method. Response spectrum solution is also available as an option.

4.1.4.1.6.2 Program Version and Computer. The DYSEA version now operating on the Honeywell 6000 computer of GE, Nuclear Energy Systems Division, was developed at GE by modifying the SAPIV program. Capability was added to handle the hydrodynamic mass effect due to fluid-structure interaction in the reactor. It can handle three-dimensional dynamic problems with beam, trusses, and springs. Both acceleration time histories and response spectra may be used as input.

4.1.4.1.6.3 History of Use. The DYSEA program was developed in the Summer of 1976. It has been adopted as a standard production program since 1977 and it has been used extensively in all dynamic and seismic analysis of the RPV and internals/building system.

4.1.4.1.6.4 Extent of Application. The current version of DYSEA has been used in all dynamic and seismic analysis since its development. Results from test problems were found to be in close agreement with those obtained from either verified programs or analytic solutions.

4.1.4.1.7 SHELL 5

4.1.4.1.7.1 Program Description. SHELL 5 is a finite shell element program used to analyze smoothly curved thin shell structures with any distribution of elastic material properties, boundary constraints, and mechanical thermal and displacement loading conditions. The basic element is a triangle whose membrane displacement fields are linear polynomial functions, and whose bending displacement field is a cubic polynomial function (Reference 4.1-13). Five degrees of freedom (three displacements and two bending rotations) are obtained at each nodal point. Output displacements and stresses are in a local (tangent) surface coordinate system.

Due to the approximation of element membrane displacements by linear functions, the in-plane rotation about the surface normal is neglected. Therefore, the only rotations considered are due to bending of the shell cross section and application of the method is not recommended for shell intersection (or discontinuous surface) problems where in-plane rotation can be significant.

4.1.4.1.7.2 Program Version and Computer. A copy of the source deck of SHELL 5 is maintained by GE/NED by Y. R. Rashid, one of the originators of the program. SHELL 5 operates on the UNIVAC 1108 computer.

4.1.4.1.7.3 History of Use. SHELL 5 is a program developed by Gulf General Atomic Incorporated (Reference 4.1-14) in 1969. The program has been in production status at Gulf General Atomic, GE, and at other major computer operating systems since 1970.

4.1.4.1.7.4 Extent of Application. SHELL 5 has been used at GE to analyze reactor shroud support and torus. Satisfactory results were obtained.

4.1.4.1.8 HEATER

4.1.4.1.8.1 Program Description. HEATER is a computer program used in the hydraulic design of feedwater spargers and their associated delivery header and piping. The program utilizes test data obtained by GE using full scale mockups of feedwater spargers combined with a series of models which represents the complex mixing processes obtained in the upper plenum, downcomer, and lower plenum. Mass and energy balances throughout the nuclear steam supply system are modeled in detail (Reference 4.1-15).

4.1.4.1.8.2 Program Version and Computer. This program was developed at GE/NED in FORTRAN IV for the Honeywell 6000 computer.

4.1.4.1.8.3 History of Use. The program was developed by various individuals in GE/NED beginning in 1970. The present version of the program has been in operation since January 1972.

4.1.4.1.8.4 Extent of Application. The program is used in the hydraulic design of the feedwater spargers for each BWR plant, in the evaluation of design modifications, and the evaluation of unusual operational conditions.

4.1.4.1.9 FAP-71 (Fatigue Analysis Program)

4.1.4.1.9.1 Program Description. The FAP-71 computer code, or Fatigue Analysis Program, is a stress analysis tool used to aid in performing ASME-III Nuclear Vessel Code structural design calculations. Specifically, FAP-71 is used in determining the primary plus secondary stress range and number of allowable fatigue cycles at points of interest. For structural locations at which the $3S_m$ *(P+Q) ASME Code limit is exceeded, the program can perform either (or both) of two elastic-plastic fatigue life evaluations: 1) the method reported in ASME Paper 68-PVP-3, 2) the present method documented in Paragraph NB-3228.3 of the 1971 Edition of the ASME Section III Nuclear Vessel Code. The Program can accommodate up to 25 transient stress states on as many as 20 structural locations.*

4.1.4.1.9.2 Program Version and Computer. The present version of FAP-71 was completed by L. Young of GE/NED in 1971 (Reference 4.1-16). The program currently is on the NED Honeywell 6000 computer.

4.1.4.1.9.3 History of Use. Since its completion in 1971, the program has been applied to several design analyses of GE BWR vessels.

4.1.4.1.9.4 Extent of Use. The program is used in conjunction with several shell analysis programs in determining the fatigue life of BWR mechanical components subject to thermal transients.

4.1.4.1.10 CREEP/PLAST

4.1.4.1.10.1 Program Description. A finite element program is used for the analysis of two-dimensional (plane and axisymmetric) problems under conditions of creep and plasticity. The creep formulation is based on the memory theory of creep in which the constitutive relations are cast in the form of hereditary integrals. The material creep properties are built into the program and they represent annealed 304 stainless steel. Any other creep properties can be included if required.

The plasticity treatment is based on kinemetic hardening and von Mises yield criterion. The hardening modulus can be constant or a function of strain.

4.1.4.1.10.2 Program Version and Computer. The program can be used for elastic-plastic analysis with or without the presence of creep. It can also be used for creep analysis without the presence of instantaneous plasticity. A detailed description of theory is given in Reference 4.1-17. The program is operative on UNIVAC-1108.

4.1.4.1.10.3 History of Use. This program was developed by Y. R. Rashid (Reference 4.1-17) in 1971. It underwent extensive program testing before it was put on production status.

4.1.4.1.10.4 Extent of Application. The program is used at GE/NED in the channel cross section mechanical analysis.

4.1.4.2 Fuel Rod Thermal Analysis

Thermal design analyses of the fuel and core were performed to verify that design criteria are met (see References 4.1-1, 4.1-4 and 4.1-5).

4.1.4.3 Reactor Systems Dynamics

The analysis techniques used in reactor systems dynamics are described in Sections S.1.3 and S.4 of Reference 4.1-1. A complete stability analysis for the reactor coolant system is provided in Section 4.4.4.2.

4.1.4.4 Nuclear Engineering Analysis

The analysis techniques are described in the fuel design reports (see Reference 4.1-1).

4.1.4.5 Neutron Fluence Calculations

See Section 4.3.2.8.

4.1.4.6 Thermal Hydraulic Calculations

The digital computer program uses a parallel flow path model to perform the steady-state BWR reactor core thermal-hydraulic analysis. Program input includes the core geometry, operating power, pressure, coolant flow rate, inlet enthalpy, and the power distribution within the core. Output from the program includes core pressure drop, coolant flow distribution, critical power ratio, and axial variations of quality, density, and enthalpy for each fuel type.

4.1.5 REFERENCES

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4.1-3 Fuel Bundle Information Report for Columbia (most recent approved version referenced in COLR).

4.1-4 "GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II)," NEDC-33270P, (most recent version referenced in COLR).

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4.1-13 R. W. Clough and C. P. Johnson, A Finite Element Approximation For the Analysis of Thin Shells, International Journal Solid Structures, Vol. 4, 1968.

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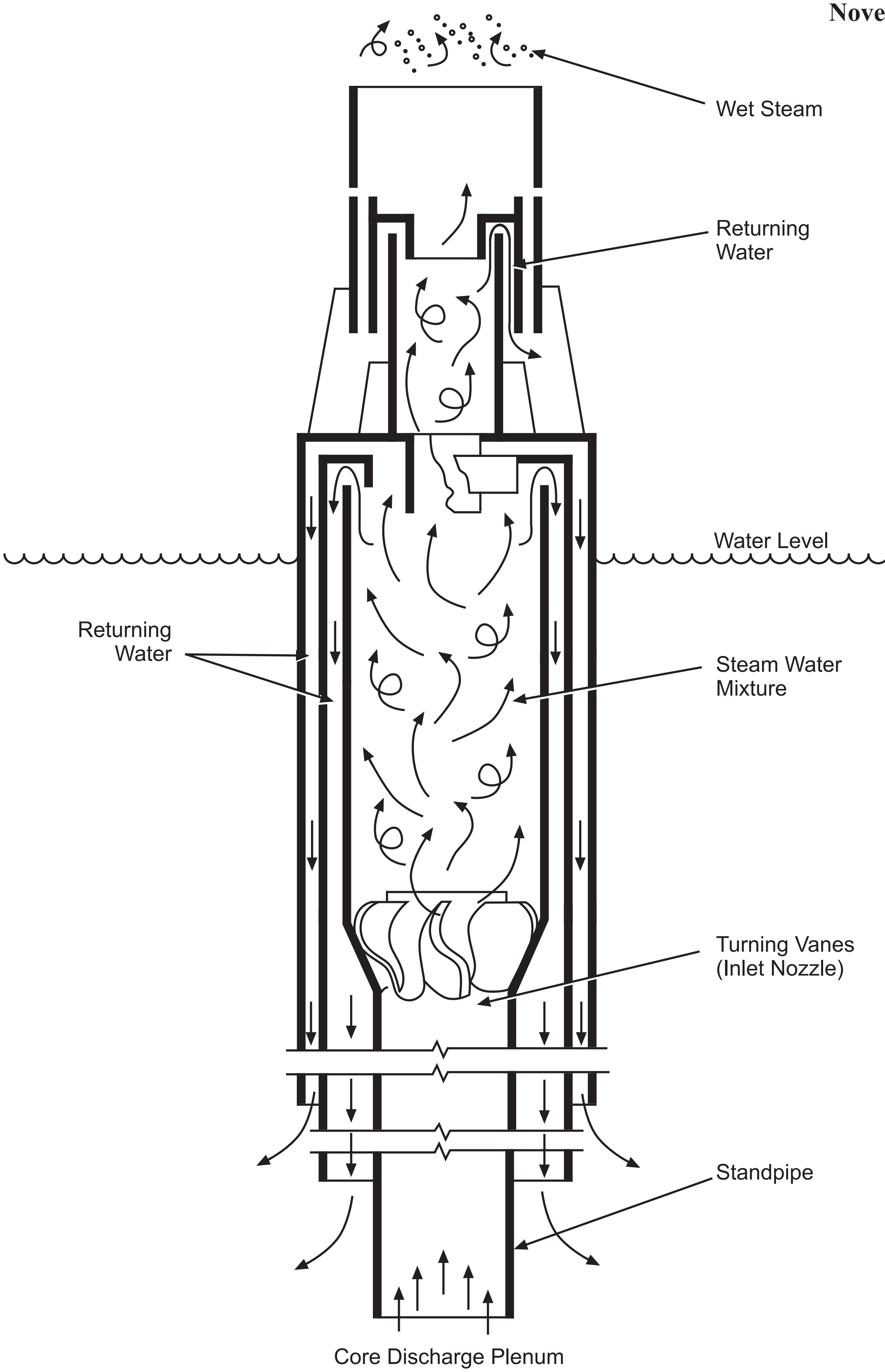
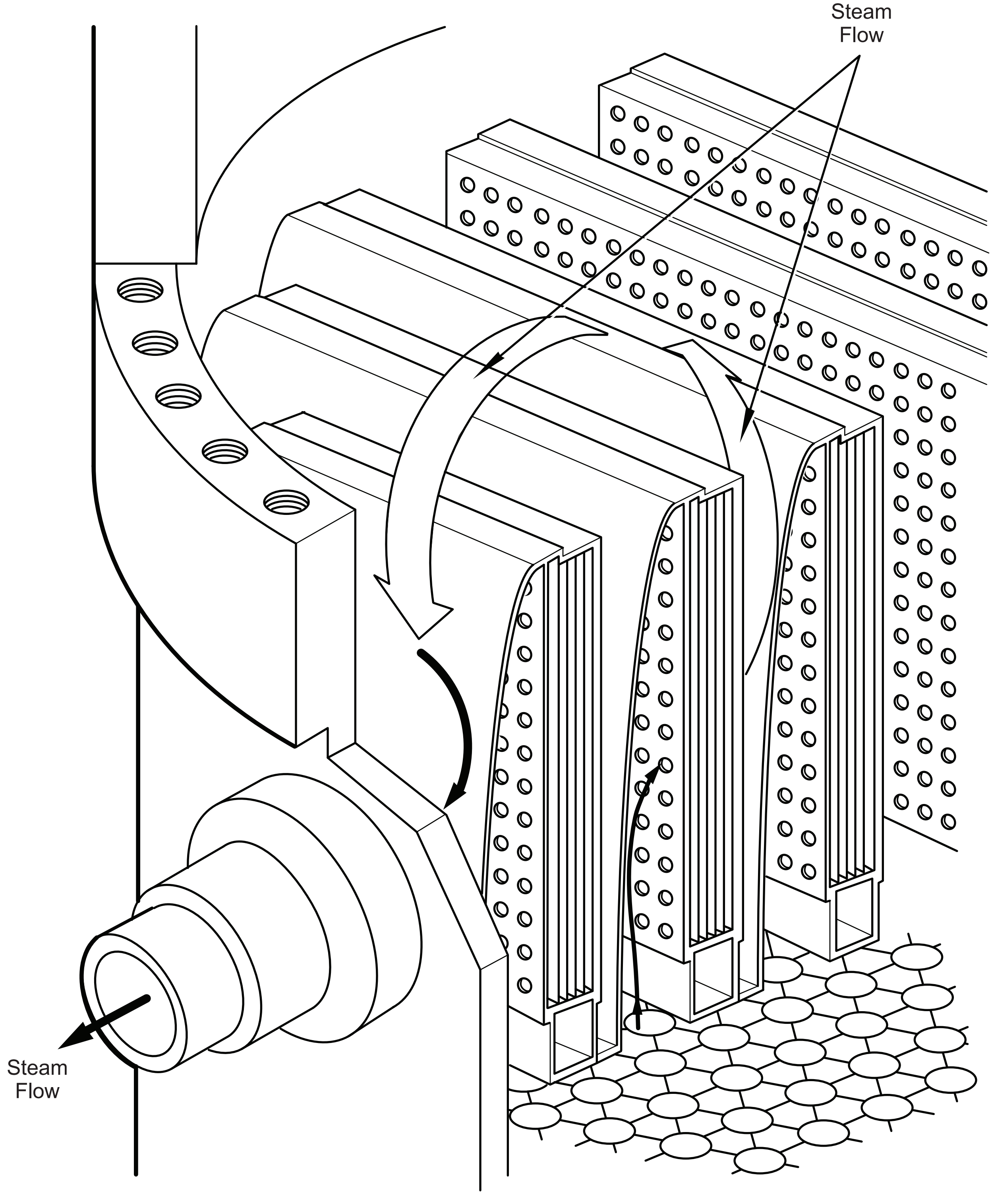


Columbia Generating Station
Final Safety Analysis Report

Steam Separator

Draw. No. 960690.95	Rev.	Figure 4.1-1



Columbia Generating Station
Final Safety Analysis Report

Steam Dryer Panel

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4.2 FUEL SYSTEM DESIGN

See Appendix A, Section A.4.2 of Reference 4.2-1.

4.2.1 DESIGN BASES

General Electric BWR fuel assembly and channel design bases, analytical methods, and evaluation results are described in Reference 4.2-1 (Appendix A, subsection A.4.2.1), Reference 4.2-6 and Reference 4.2-25.

4.2.1.1 Fuel System Damage Limits

4.2.1.1.1 Stress/Strain Limits

See subsection 2.2.1.1.2 of Reference 4.2-1.

4.2.1.1.2 Fatigue Limits

See subsections 2.2.1.2.2 of Reference 4.2-1.

4.2.1.1.3 Fretting Wear Limits

Fretting wear is considered in the mechanical design analysis of the assembly. See subsection 2.2.1.3.2 of Reference 4.2-1.

4.2.1.1.4 Oxidation, Hydriding, and Corrosion Limits

See subsection 2.2.1.4.2.2 of Reference 4.2-1 for the hydriding limit. Oxidation and corrosion are considered in the mechanical design analysis. See subsection 2.2.1.4.1.2 of Reference 4.2-1.

4.2.1.1.5 Dimensional Change Limits

See Reference 4.2-6 and subsection 2.2.1.5.2 of Reference 4.2-1.

4.2.1.1.6 Internal Gas Pressure Limit

See subsection 2.2.1.6.2 of Reference 4.2-1

.

4.2.1.1.7 Hydraulic Loads Limits

See subsection 2.2.1.7.2 of Reference 4.2-1.

4.2.1.1.8 Control Rod Reactivity Limits

See Section 3.2 and 3.3 of Reference 4.2-1 and Reference 4.2-7.

4.2.1.2 Fuel Rod Failure Limits

4.2.1.2.1 Hydriding Limits

See subsection 2.2.2.1 of Reference 4.2-1.

4.2.1.2.2 Cladding Collapse Limits

See subsection 2.2.2.2.2 of Reference 4.2-1.

4.2.1.2.3 Fretting Wear Limits

See subsection 2.2.1.3.2 of Reference 4.2-1.

4.2.1.2.4 Overheating of Cladding Limits

See subsections 2.2.2.4 and 4.3.1 of Reference 4.2-1.

4.2.1.2.5 Overheating of Pellet Limits

See subsection 2.2.2.5.2 of Reference 4.2-1.

4.2.1.2.6 Excessive Fuel Enthalpy Limits

See subsection 2.2.2.6 of Reference 4.2-1.

4.2.1.2.7 Pellet-Cladding Interaction Limits

See subsection 2.2.2.7.2 of Reference 4.2-1.

4.2.1.2.8 Bursting Limits

See subsections 2.2.2.8 and 2.2.3.4 of Reference 4.2-1.

4.2.1.2.9 Mechanical Fracturing Limits

See subsection 2.2.2.9.2 of Reference 4.2-1.

4.2.1.3 Fuel Coolability Limits

4.2.1.3.1 Cladding Embrittlement Limits

See Reference 4.2-10, subsection 2.2.3.1 of Reference 4.2-1.

4.2.1.3.2 Violent Expulsion of Fuel Limits

See subsection 2.2.3.2 of Reference 4.2-1.

4.2.1.3.3 Generalized Cladding Melt Limits

Same as Section 4.2.1.3.1 and subsection 2.2.3.3 of Reference 4.2-1.

4.2.1.3.4 Fuel Rod Ballooning Limits

Same as Section 4.2.1.2.8.

4.2.1.3.5 Structural Deformation Limits

See subsection 2.2.3.5 of Reference 4.2-1.

4.2.2 DESCRIPTION AND DESIGN DRAWINGS

See References 4.2-2 and 4.2-3.

4.2.2.1 Control Rods

The control rods (typical configuration shown in Figures 4.2-1.1, 4.2-1.2, and 4.2-1.3) perform the dual function of power shaping and reactivity control. Power distribution in the core is controlled during operation of the reactor by manipulating selected patterns of control rods. Control rod withdrawal tends to counterbalance steam void effects at the top of the core and results in significant axial power flattening.

The original control rods consists of a sheathed cruciform array of stainless steel tubes filled with boron-carbide (B_4C) powder. The control rods are 9.88 in. in total span and are separated uniformly throughout the core on a 12-in. pitch maximum. Each control rod is surrounded by four fuel assemblies.

The main structural member of a control rod is made of type 304 stainless steel and consists of a top handle, an original bottom casting with a velocity limiter and control rod drive coupling, a vertical cruciform center post, and four U-shaped absorber tube sheaths. The top handle, bottom casting, and center post are welded into a single skeletal structure. The U-shaped sheaths are resistance welded to the center post, handle, and castings to form a rigid housing to contain the boron-carbide-filled absorber rods. Rollers at the top and bottom of the control rod guide the control rod as it is inserted and withdrawn from the core. The control rods are cooled by the core bypass flow. The U-shaped sheaths are perforated to allow the coolant to circulate freely about the absorber tubes. Operating experience has shown that control rods constructed as described above are not susceptible to dimensional distortions.

The boron-carbide (B_4C) powder in the absorber tubes is compacted to about 70% of its theoretical density. The boron-carbide contains a minimum of 76.5% by weight natural boron. The boron-10 (B-10) minimum content of the boron is 18% by weight. Absorber tubes are made of type 304 stainless steel. Each absorber tube is 0.188-in. O.D. and has a 0.025-in. wall thickness. Absorber tubes are sealed by a plug welded into each end. The boron-carbide is longitudinally separated into individual compartments by stainless steel balls at approximately 16-in. intervals. The steel balls are held in place by a slight crimp of the tube. Should boron-carbide tend to sinter in service, the steel balls will keep the resulting void spaces distributed over the length of the absorber tube.

Some of the control rods have been replaced with Duralife 215 or Marathon control rods. The main structural member of the Duralife 215 control rod design is made of stainless steel and consists of a top handle, a tie rod, a bottom control rod drive coupling, and four sheaths containing the neutron absorber. The top handle, tie rod, velocity limiter, and sheaths are welded into a single structure. The neutron absorber in each wing of the sheath consists of 18 high-purity stainless-steel tubes filled with boron-carbide, three hafnium rods at the edge of the wing, and a hafnium plate at the top.

The sheaths of the Duralife 215 blades are attached to the structure with full fusion corner welds to the handle, tie rod, and velocity limiter to form a rigid housing. Inconel X750 rollers at the top and bottom of the control rod guide the control rod as it is inserted and withdrawn from the core. These rollers rotate on PH 13-8 Mo pins. The sheaths are perforated and the hafnium absorber plate has coolant grooves to allow the coolant to circulate freely about the absorber and flush the joint between the sheath and handle.

The number of boron carbide absorber rods in each wing has been changed from 19 rods with an I.D. of 0.138 in. to 18 rods with an I.D. of 0.148 in. The outside diameter remains the same. The length of the absorber column in these rods has been reduced from 143 in. to 137 in. to accommodate a top 6-in.-high hafnium plate. In addition, three 0.188 in. O.D. hafnium rods have been added to the edge of each wing.

The Marathon control rod blade consists of a top handle, a segmented tie rod (for weight savings), a bottom control rod coupling/velocity limiter and four wings consisting of an array of square tubes. The square tubes each have four lobes to allow adjacent tubes to be welded to each other. The absorber tubes are welded lengthwise to form the four wings of the control rod. Each wing is comprised of 17 absorber tubes. The four wings are then welded to the tie rod to form the cruciform-shaped member of the control rod.

The square tubes are circular inside and are loaded with either B_4C or hafnium. The combination of absorbers and absorber tubes is based on the needed initial reactivity worth. In addition, empty capsules are used in some absorber tubes to provide a plenum for helium released during B_4C burnup.

A comparison of the original, the Duralife 215 and the Marathon control rod dimensions and materials is given in Table 4.2-1.

4.2.2.2 Velocity Limiter

The control rod velocity limiter (see Figure 4.2-2) is an integral part of the bottom assembly of each control rod. This feature protects against a high reactivity insertion rate by limiting the control rod velocity in the event of a control rod drop accident. It is a one-way device in that the control rod scram velocity is not significantly affected but the control rod dropout velocity is reduced to a permissible limit.

The velocity limiter is in the form of two nearly mated conical elements that act as a large clearance piston inside the control rod guide tube. The lower conical element is separated from the upper conical element by four radial spacers 90 degrees apart.

The hydraulic drag forces on a control rod are approximately proportional to the square of the rod velocity and are negligible at normal rod withdrawal or rod insertion speeds. However, during the scram stroke the rod reaches high velocity, and the drag forces must be overcome by the drive mechanism.

To limit control rod velocity during dropout but not during scram, the velocity limiter is provided with a streamlined profile in the scram (upward) direction. Thus, when the control rod is scrammed water flows over the smooth surface of the upper conical element into the annulus between the guide tube and the limiter. In the dropout direction, however, water is trapped by the lower conical element and discharged through the annulus between the two conical sections. Because this water is forced in a partially reversed direction into water flowing upward in the annulus, a severe turbulence is created, and this slows the descent of the control rod assembly to less than 5 ft/sec.

4.2.3 DESIGN EVALUATION

See Appendix A, subsection A.4.2.3 of Reference 4.2-1.

4.2.3.1 Fuel System Damage Evaluation

4.2.3.1.1 Stress/Strain Evaluation

Fuel rod internal pressure has been shown to remain below system pressure for rod peak burnups well beyond anticipated achieved burnup. For GNF fuel see section 2.2.1.1.3 of Reference 4.2-1.

4.2.3.1.2 Fatigue Evaluation

See subsection 2.2.1.2.3 of Reference 4.2-1.

4.2.3.1.3 Fretting Wear Evaluation

See Reference 4.2-12, subsection 2.2.1.3.3 of Reference 4.2-1.

4.2.3.1.4 Oxidation, Hydriding, and Corrosion Evaluation

See subsections 2.2.1.4.1.3 and 2.2.1.4.2.3 of Reference 4.2-1.

4.2.3.1.5 Dimensional Change Evaluation

See Reference 4.2-6, subsection 2.2.1.5.3 of Reference 4.2-1.

4.2.3.1.6 Internal Gas Pressure Evaluation

See subsection 2.2.6 of Reference 4.2-3 and Section 3.2.6 of reference 4.2-2. The internal pressure is used in conjunction with other loads on the fuel rod cladding when calculating cladding stresses and comparing these stresses to the design criteria. The analysis results show that the calculated cladding stresses are below allowable limits even with internal gas pressure and other loads at end of life normal and transient conditions, respectively.

4.2.3.1.7 Hydraulic Load Evaluation

See subsection 2.2.1.7.3 of Reference 4.2-1, 4.2-12 and Section 3.9.

4.2.3.1.8 Control Rod Reactivity Evaluation

See Appendix A, subsection A.4.3.2 of Reference 4.2-1. Energy Northwest calculates the fluence of each control blade using an appropriate conversion factor for fuel exposures adjacent to the control blade. Control blade shuffling or replacement is based on the calculated blade fluence as compared to vendor allowed values (Reference 4.2-22). The vendor allowed values account for the reduction in control blade worth due to a combination of boron-10 depletion and boron loss resulting from cracking of the absorber tubes.

4.2.3.2 Fuel Rod Failure

4.2.3.2.1 Hydriding Evaluation

See Section 4.2.3.1.4.

4.2.3.2.2 Cladding Collapse Evaluation

See subsection 2.2.8 of Reference 4.2-3 and Section 3.2.8 of Reference 4.2-2.

4.2.3.2.3 Fretting Wear Evaluation

See Section 4.2.3.1.3.

4.2.3.2.4 Overheating of Cladding Evaluation

See section 2.6 of Reference 4.2-3 and Section 3.6 of Reference 4.2-2.

4.2.3.2.5 Overheating of Pellet Limits

See subsection 2.2.9 of Reference 4.2-3 and Section 3.2.9 of Reference 4.2-2.

4.2.3.2.6 Excessive Fuel Enthalpy Evaluation

See Section 15.4.9 and subsection 2.12 of Reference 4.2-3 and Section 3.12 of Reference 4.2-2.

4.2.3.2.7 Pellet-Cladding Interaction Evaluation

Calculated results do not exceed the 1% plastic strain or minimum critical power ratio (MCPR) fuel cladding integrity safety limits; thus fuel pellet melting does not occur. These are the most applicable general design criteria for pellet cladding interaction (PCI) phenomena. While PCI-induced fuel failures remain a commercially undesirable problem, they are not a safety concern. Boiling water reactors (BWRs) have been designed and licensed with provisions to accommodate operating with fuel cladding perforation, and field experience confirms that plants do indeed operate within radiological release limits.

Operation below the thermal-mechanical limits historically has resulted in very few pellet-cladding interaction (PCI) fuel failures. Furthermore power maneuvering guidelines have been developed that have further reduced fuel failures due to the PCI mechanism.

4.2.3.2.8 Bursting Evaluation

See subsection 2.11.1 of Reference 4.2-3 and Section 3.11.1 of Reference 4.2-2.

4.2.3.2.9 Mechanical Fracturing Evaluation

See Reference 4.2-12 and subsection 2.2.2.9.3 of Reference 4.2-1.

4.2.3.3 Fuel Coolability Evaluation

4.2.3.3.1 Cladding Embrittlement Evaluation

See Section 4.2.3.2.8 and subsection 2.2.3.1 of Reference 4.2-1.

4.2.3.3.2 Violent Expulsion of Fuel Evaluation

See Section 15.4.9 and subsection 2.12 of Reference 4.2-3 and Section 3.12 of Reference 4.2-2.

4.2.3.3.3 Generalized Cladding Melt Evaluation

See Section 4.2.3.2.8 and subsection 2.11.2 of Reference 4.2-3 and Section 3.11.2 of Reference 4.2-2.

4.2.3.3.4 Fuel Rod Ballooning Evaluation

See Section 4.2.3.2.8 and subsection 2.11.1 of Reference 4.2-3 and Section 3.11.1 of Reference 4.2-2.

4.2.3.3.5 Structural Deformation Evaluation

See Section 4.2.3.2.9.

4.2.4 TESTING, INSPECTION, AND SURVEILLANCE PLANS

4.2.4.1 Fuel Testing, Inspection, and Surveillance

See Appendix A, subsection A.4.2.4 of Reference 4.2-1.

4.2.4.2 Online Fuel System Monitoring

Columbia Generating Station (CGS) has two independent radiation detection systems that are directly capable of detecting fission product releases from failed fuel rods in an online manner. The main steam line radiation (MSLR) monitors are described in Section 11.5.2.1.1. Because the MSLR monitors are located relatively close to the reactor core, they are capable of sensing gross fission product releases in a few seconds.

The offgas system radiation (OGSR) monitors are capable of detecting low-level emissions of noble gases in 2 to 3 minutes after the gases leave the fuel. The OGSR monitors are described in more detail in Section 11.5.2.2.1.

4.2.4.3 Post-Irradiation Surveillance

The following fuel surveillance will be conducted after the refueling outage for the CGS unit on fuel discharged during the refueling outage that has given indication of gross cladding defects or anomalies during plant operation.

Scope

The fuel surveillance program, developed to provide verification of the reliable performance of the CGS fuel design, will consist of the following inspections and measurements:

a. Visual inspection of the peripheral rods will be performed on discharged fuel, that has given indication of gross cladding defects or anomalies during plant operation, after each refueling outage. The examination will be capable of detecting and characterizing generic gross cladding defects or anomalies; and

b. If anomalous behavior of the fuel cladding, components of the fuel assembly, or significant rod bow are detected by visual examination, further investigation, and measurements of such significant anomalies will be conducted after the refueling outages.

Implementation

a. Onsite receiving inspection of all the initial core fuel assemblies and subsequent reloads will be documented. Any significant anomalies detected will be documented;

b. Fuel performance history and related plant operational data will be monitored and analyzed during operation;

c. Assemblies discharged during each refueling outage that have given indication of gross cladding defects or anomalies during plant operation will be selected for visual inspection. The visual examination of the peripheral rods will include observations for cladding defects, fretting, rod bowing, missing components, corrosion, crud deposition, and geometric distortions. The defects or anomalies on the cladding surface area examined will be either videotaped or photographed to document and characterize the anomaly;

d. In the event that significant anomalies are observed during the refueling examination, all other discharged assemblies may also be visually inspected. The results will be analyzed to determine fuel utilization strategy and possible safety implications in accordance with the operating procedures and applicable licensing requirements;

e. If unusual defects are observed, the fuel with the defects and the applicable operational data will be investigated and further appropriate tests and examination of the defected fuel will be performed; and

f. If defects of an unusual nature are detected, an oral report will be made to the NRC after the completion of the inspection activities. Under normal conditions, the report will contain visual examination summaries confirming the reliable performance of the fuel assemblies. In the event that significant anomalies or unusual defects are observed, the report will contain the description and related data of onsite receiving inspection and operational conditions. Evaluation and studies to identify causes for any encountered anomalies or defects will be assessed and the results will be reported to the NRC as they become available.

4.2.4.4 Channel Management Program

Fuel channels are subject to bulge, bow, and elongation when irradiated in reactors. Excessive deformations (bow and bulge) could produce traversing in-core probe asymmetries and control blade frictional resistance.

All new reload fuel will be loaded with new channels. Energy Northwest has in the past reinserted requalified channels in CGS but has transitioned away from channel reuse (References 4.2-13, 4.2-14, and 4.2-15).

The Safety Evaluation Report Related to the Operation of WPPSS Nuclear Project No. 2, Supplement 3 (Reference 4.2-16), discusses measurement of selected discharged fuel channels for deflection. The intent of this deflection measurement was to qualify channels for reuse. Because Energy Northwest no longer reuses channels, the qualification of channel reuse has been discontinued.

In addition to the above channel management program, Energy Northwest is taking a number of operational actions to monitor channel distortion in the core. These include Technical Specifications requirements for periodic scram testing and rod notch testing, which would provide an indication of pending driveline friction between control rod and bowed channels. Should either of these tests suggest a driveline friction problem, the tests described in NEDE-21354-P, Reference 4.2-6, would then be used to isolate the cause.

4.2.5 REFERENCES

4.2-1 General Electric Company, General Electric Standard Application for Reactor Fuel (NEDE-24011-P-A), and Supplement for United States (NEDE-24011-P-A-US) (most recent approved version referenced in COLR).

4.2-2 "GNF2 Advantage Generic compliance with NEDE-24011-P-A (GESTAR II)," NEDC-33270P, (most recent version referenced in COLR).

4.2-3 "GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," NEDC-32868P, (most recent version referenced in COLR).

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4.2-5 Deleted.

4.2-6 General Electric Company, BWR Fuel Channel Mechanical Design and Deflection, NEDE-21354-P, September 1976.

4.2-7 General Electric Company, Control Blade Lifetime with Potential B_4C Loss, NEDO-24226 and Supplement 1.

4.2-8 Deleted.

4.2-9 Deleted.

4.2-10 General Electric Company, Analytical Model for Loss-of-Coolant Analyses in Accordance with 10 CFR 50 Appendix K, NEDO-20566-A, September 1986.

4.2-11 Deleted.

4.2-12 General Electric Company, GE Duralife 215 Control Rod Safety Evaluation, GENE-778-028-0790, Revision 2, July 1992.

4.2-13 Letter and Attachment from G. C. Sorensen, Manager, Regulatory Programs, Supply System to NRC, Subject: Nuclear Plant No. 2, Operating License NPF-21, Modification to WNP-2 Cycle Reload Submittal and Response to NRC Bulletin 90-02: Loss of Thermal Margin Caused by Channel Box Bow, GO2-90-075, April 13, 1990.

4.2-14 Letter from G. C. Sorensen, Manager, Regulatory Programs, Supply System to NRC, Subject: Nuclear Plant No. 2, Operating License NPF-21, Final Response to NRC Bulletin 90-02; Loss of Thermal Margins Caused by Channel Box Bow, GO2-90-162, September 28, 1990.

4.2-15 Letter and Attachments from P. L. Eng., Project Manager, NRC to G. C. Sorensen, Manager, Regulatory Programs, Supply System, Evaluation of Response to NRC Bulletin 90-92; Loss of Thermal Margins Caused by Channel Box Bow (TAC No. 76354), April 22, 1991.

4.2-16 Nuclear Regulatory Commission, Safety Evaluation Report Related to the Operation of WPPSS Nuclear Project No. 2, NUREG-0892, Supplement 3, Washington, D.C., May 1983.

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4.2-18 Deleted.

4.2-19 Deleted.

4.2-20 General Electric Company, GE Marathon Control Rod Assembly (NEDE-31758P-A), October 1991.

4.2-21 Deleted.

4.2-22 General Electric Company, GE BWR Control Rod Lifetime, NEDE-30931 (most recent revision specified in CVI 768-00,91).

4.2-23 Deleted.

4.2-24 Deleted.

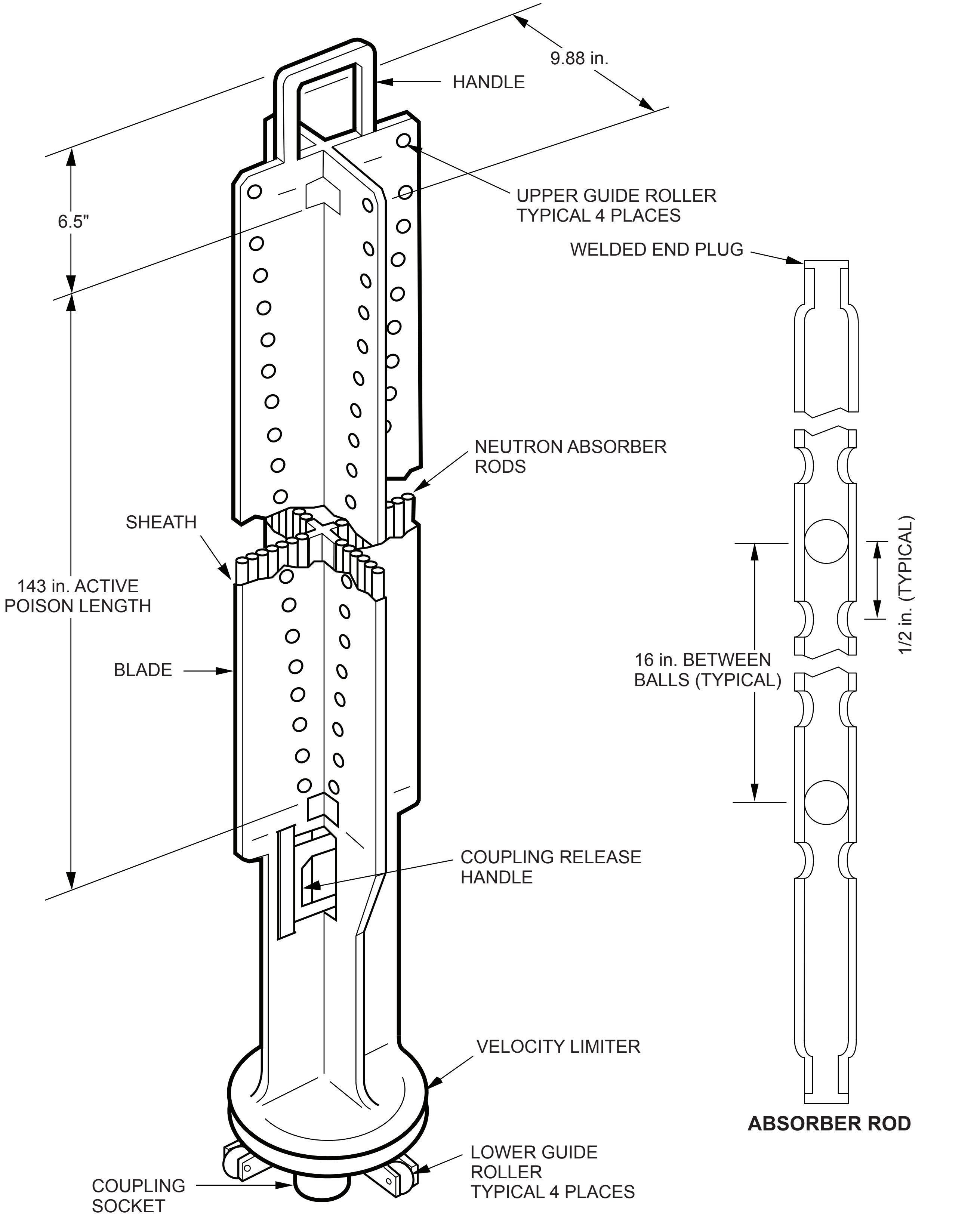
4.2-25 General Electric Company, Fuel Assembly Evaluation of Combined Safe Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) Loadings, NEDE-21175-3-P, July 1982.

4.2-26 Deleted.

Table 4.2-1

Control Rod Parameters

	Original Equipment	Duralife 215	Marathon
Control rod weight, lb (kg)	186 (84.4)	204 (92.5)	197 (89.4)
Absorber rod - boron-carbide			
Number per control rod	76	72	52
Length, in. (mm)	143 (3632)	137 (3480)	143.7 (3650)
Inside diameter, in. (mm)	0.138 (3.51)	0.148 (3.76)	0.189 (4.80)
Density, grams/cm^3	1.76 (Nominal)	1.76 (Nominal)	1.76 (70% Theoretical)
Absorber tube			
Cladding material	Stainless steel	High purity stainless steel	304S
O.D., in. (mm)	0.188 (4.78)	0.188 (4.78)	0.246 (6.248)
Wall thickness, in. (mm)	0.025 (0.635)	0.020 (0.508)	0.021 (0.533)
Absorber rods - hafnium			
Number per control rod	-	12	16
Length, in. (mm)	-	143 (3632)	143.4 (3642)
Diameter, in. (mm)	-	0.188 (4.78)	0.188 (4.78)
Density, grams/cm^3		13.1	13.0
Absorber plate - hafnium			
Number per control rod	-	4	-
Length, in. (mm)	-	6 (152)	-
Width, in. (mm)	-	3.42 (86.87)	-
Thickness, in. (mm)	-	0.188 (4.78)	-
Density, grams/cm^3	-	13.1	-
Sheath thickness, in. (mm)	0.030 (0.762)	0.034 (0.864)	-
Stiffener	Yes	No	-
Pin material	Haynes Alloy 25	PH 13-8 MO	PH 13-8 MO
Roller material	Stellite 3	Inconel X750	Inconel X750



Columbia Generating Station **Final Safety Analysis Report**	**Original Equipment (OEM) Control Rod Blade Assembly**
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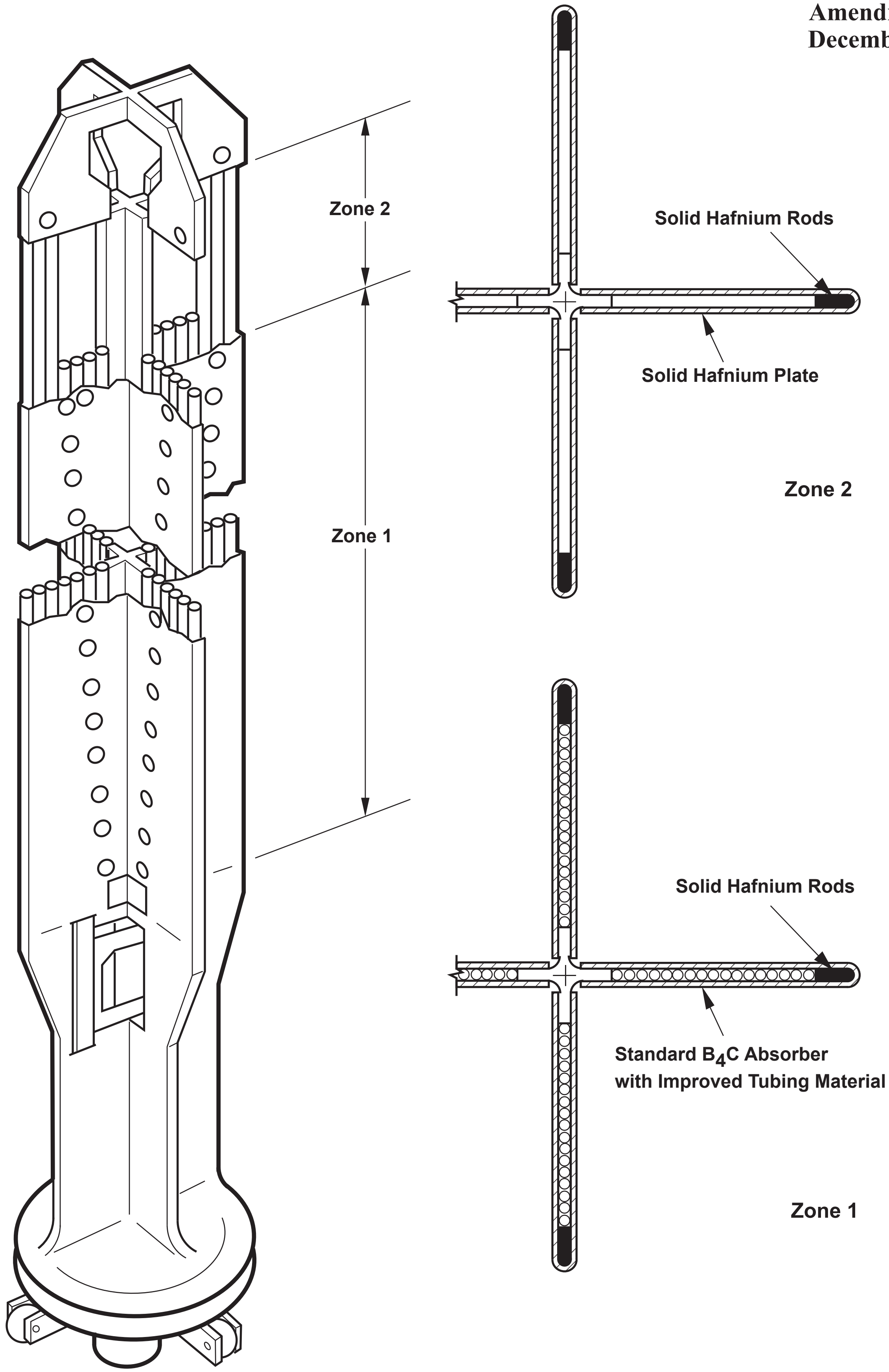

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DuraLife 215 Control Rod Blade Assembly

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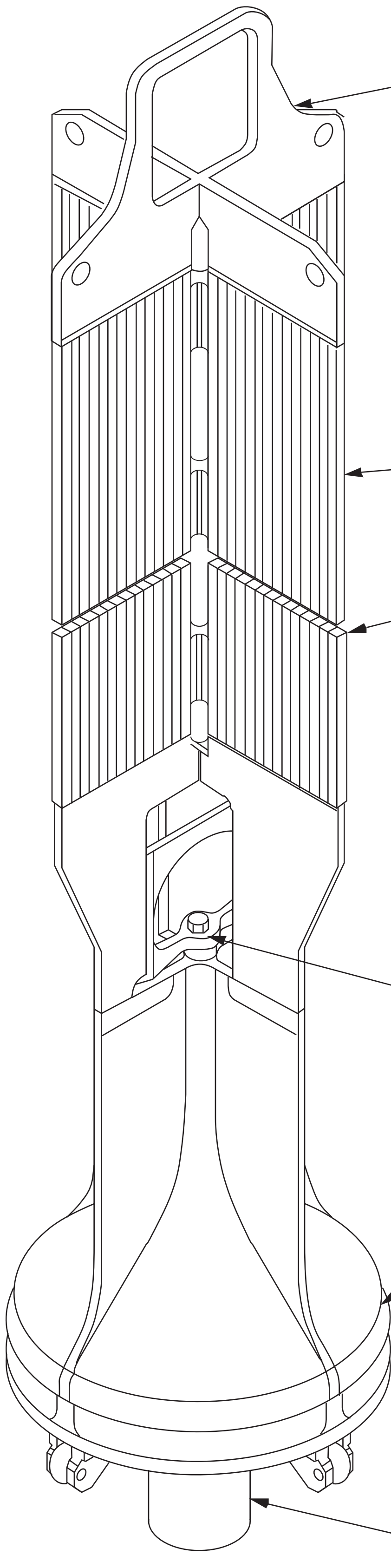

Marathon Control Rod Blade Assembly

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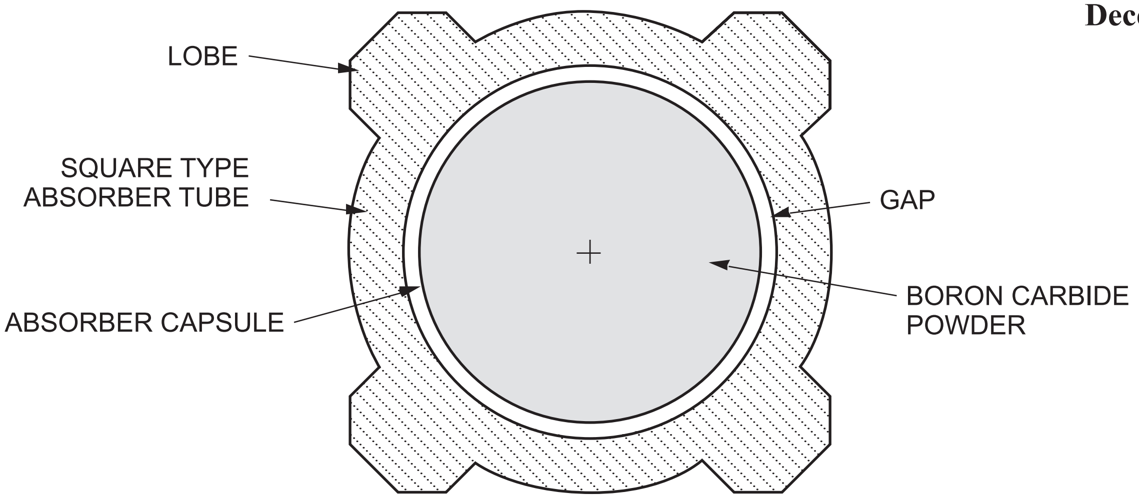
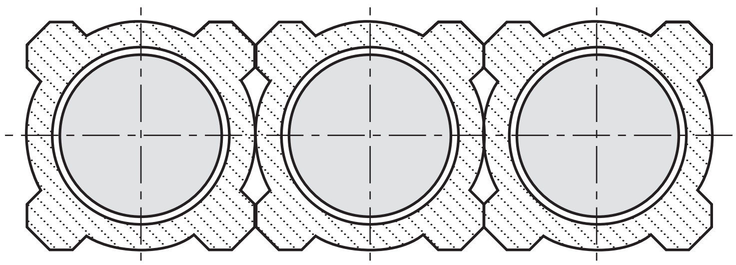
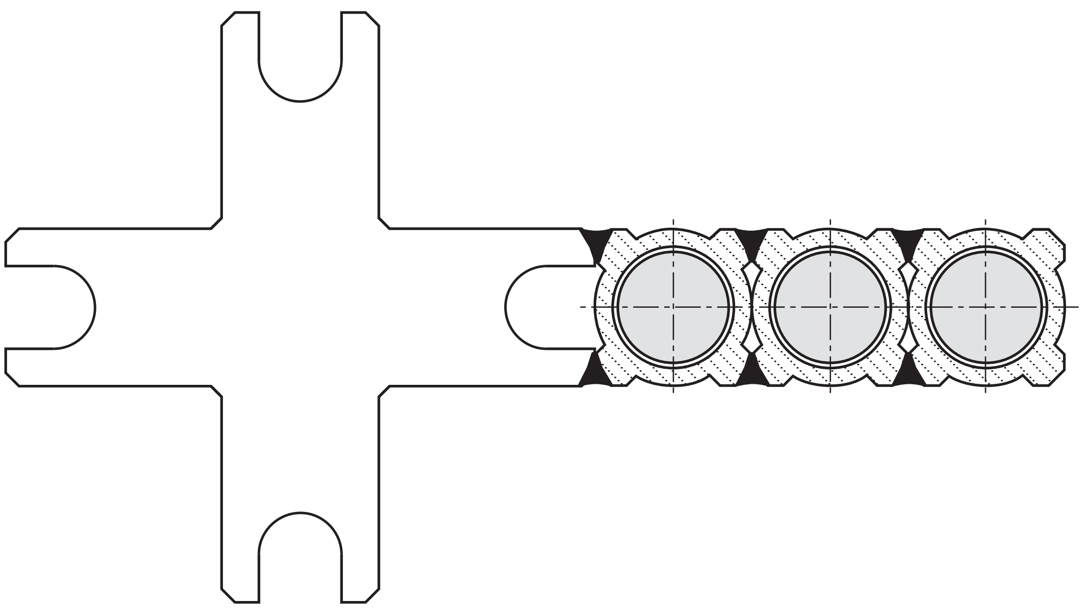
Draw. No. 010126.55	Rev.	Figure 4.2-1.3



B_4C Placement in Capsules and Absorber Tubes



Absorber Tubes
(Before Welding)



Absorber Tubes Welded to Tie Rods

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Marathon Control Rod Blade Absorber Details

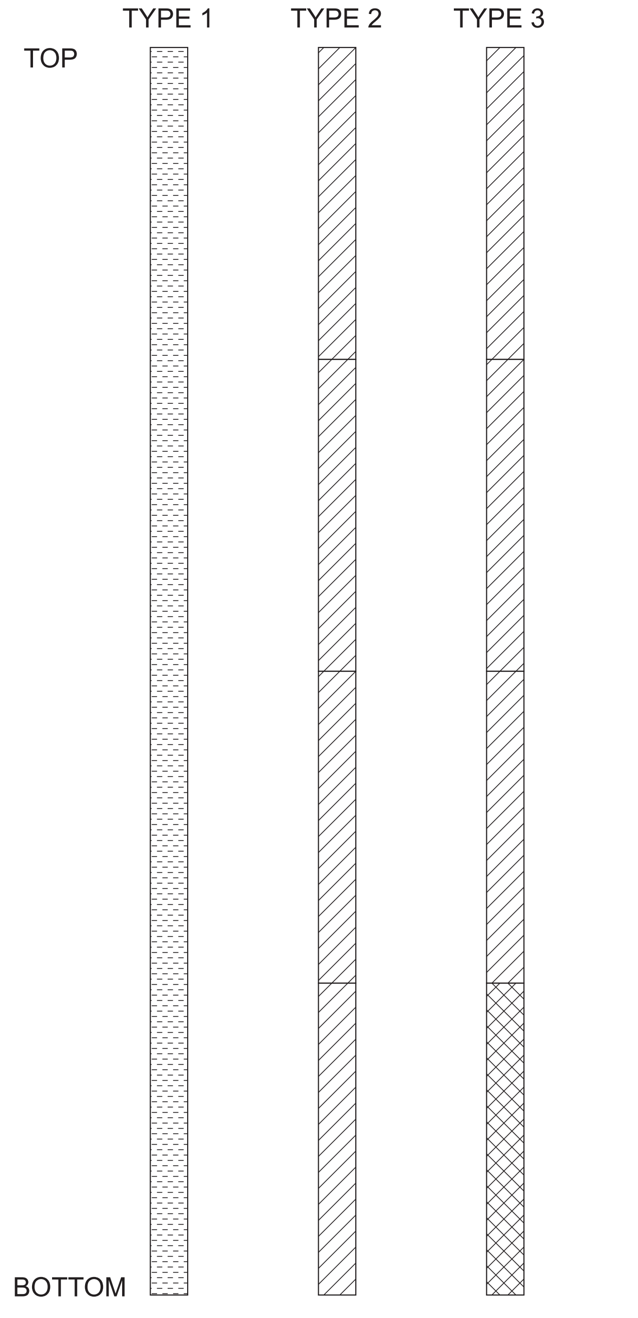
Draw. No. 010126.56	Rev.	Figure 4.2-1.4

TYPE	ABSORBER LOADING
1	ONE 143.1” LONG HAFNIUM ROD
2	FOUR 35.77” LONG B4C CAPSULES
3	THREE 35.77” LONG B4C CAPSULES ONE 23.85” LONG B4C CAPSULE ONE 11.925” LONG EMPTY CAPSULE

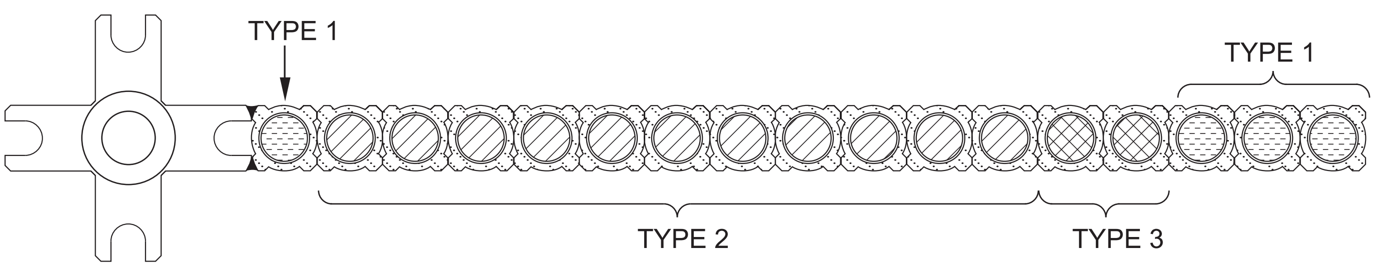
HAFNIUM

B4C ABSORBER CAPSULE

EMPTY CAPSULE



ABSORBER MATERIAL CONTAINED IN TUBES



CONTROL ROD CROSS PARTIAL SECTION

Marathon Control Rod Blade Absorber Placement

Columbia Generating Station
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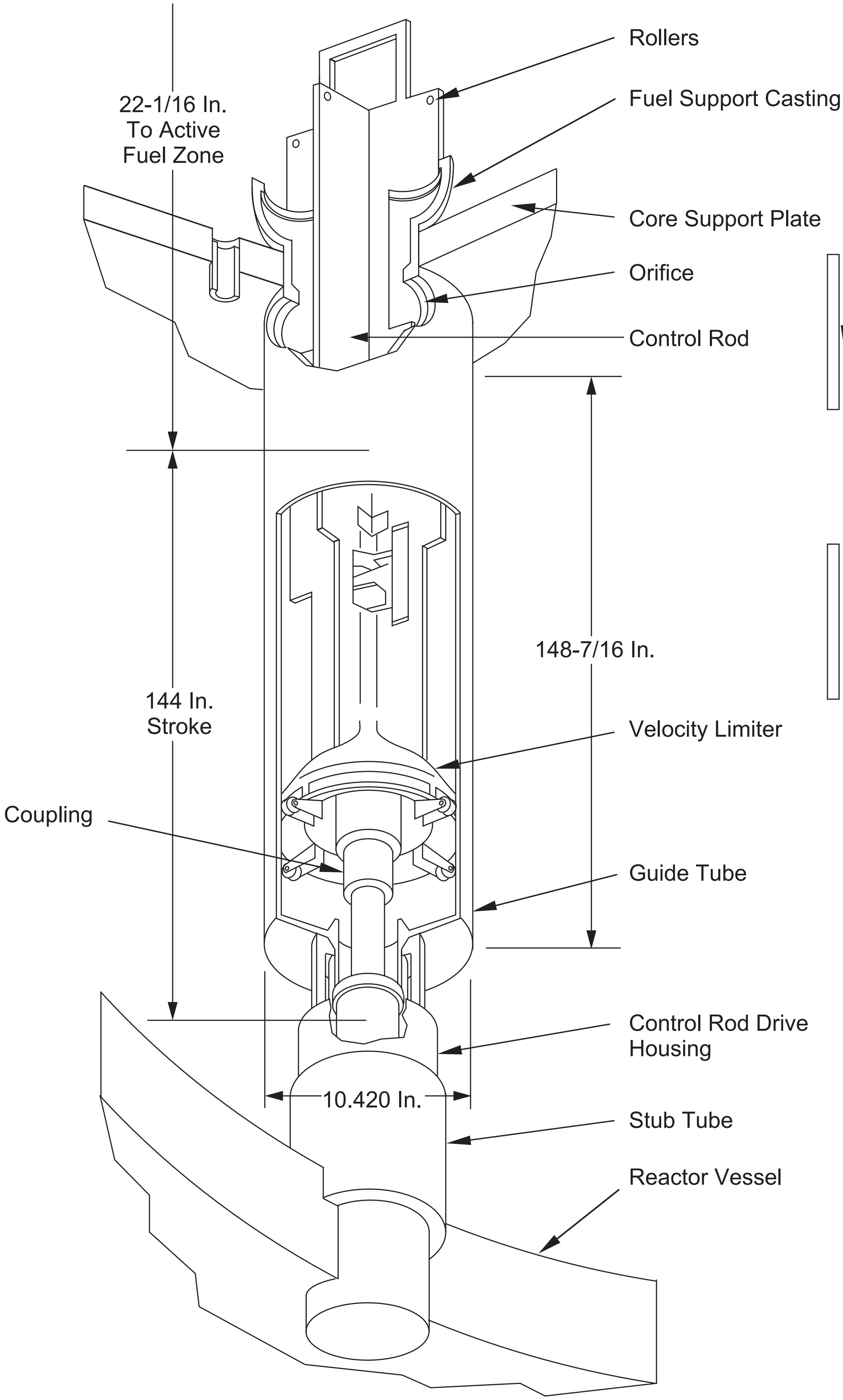
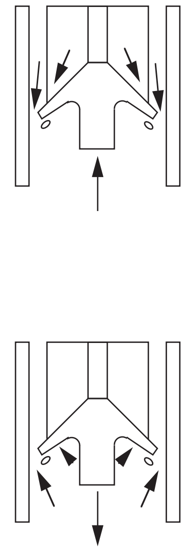
Draw. No. **010126.57** | Rev. | Figure **4.2-1.5**





Columbia Generating Station Final Safety Analysis Report	Control Rod Velocity Limiter		
	Draw. No. 960690.97	Rev.	Figure 4.2-2

4.3 NUCLEAR DESIGN

4.3.1 DESIGN BASES

See Appendix A, subsection A.4.3.1 of Reference 4.3-4.

4.3.1.1 Reactivity Basis

See Appendix A, subsection A.4.3.1.1 of Reference 4.3-4.

4.3.1.2 Overpower Bases

See Appendix A, subsection A.4.3.1.2 of Reference 4.3-4.

4.3.2 DESCRIPTION

See Appendix A, subsection A.4.3.2 of Reference 4.3-4.

4.3.2.1 Nuclear Design Description

See Appendix A, subsection A.4.3.2.1 of Reference 4.3-4. The reference core loading pattern is provided in Reference 4.3-7. See Table 4.3-2, Table 4.3-3 and Reference 4.3-9.

4.3.2.2 Power Distribution

See Appendix A, subsection A.4.3.2.2 of Reference 4.3-4.

4.3.2.2.1 Power Distribution Calculations

See References 4.3-7 and 4.3-3.

4.3.2.2.2 Power Distribution Measurements

See Appendix A, subsection A.4.3.2.2.2 of Reference 4.3-4.

4.3.2.2.3 Power Distribution Accuracy

See Appendix A, subsection A.4.3.2.2.3 of Reference 4.3-4.

4.3.2.2.4 Power Distribution Anomalies

See Appendix A, subsection A.4.3.2.2.4 of Reference 4.3-4.

4.3.2.3 Reactivity Coefficients

See Appendix A, subsection A.4.3.2.3 of Reference 4.3-4.

4.3.2.4 Control Requirements

See Appendix A, subsection A.4.3.2.4 of References 4.3-4.

4.3.2.4.1 Shutdown Reactivity

See Appendix A, subsection A.4.3.2.4.1 of Reference 4.3-4.

The cold shutdown margin for the reference core loading pattern is provided in Reference 4.3-7.

As discussed in Section 4.6.3.1.1.5, the shutdown margin with the highest worth control rod withdrawn shall be analytically determined to be at least 0.38% Δk/k or shall be determined by test to be at least 0.28% Δk/k. To ensure that the safety design basis for shutdown margin is satisfied, additional design margin is adopted during design development so that a shutdown margin of at least 1.00% Δk/k is calculated with the highest worth control rod fully withdrawn.

4.3.2.4.2 Reactivity Variations

See Appendix A, subsection A.4.3.2.6 of Reference 4.3-4.

The excess reactivity designed into the core is controlled by the control rod system supplemented by gadolinia-urania fuel rods (Reference 4.3-3).

Control rods are used during the cycle partly to compensate for burnup and partly to control the power distribution.

Reactivity balances are not used in describing BWR behavior because of the strong interdependence of the individual constituents of reactivity. Therefore, the design process does not produce components of a reactivity balance at the conditions of interest. Instead, it gives the k_{eff} representing all effects combined. Further, any listing of components of a reactivity balance is quite ambiguous unless the sequence of the changes is clearly defined.

4.3.2.5 Control Rod Patterns and Reactivity Worths

See References 4.3-1, 4.3-2 and 4.3-3.

4.3.2.6 Criticality of Reactor During Refueling

See Appendix A, subsection A.4.3.2.6 of Reference 4.3-4.

Compliance with Technical Specification shutdown margin requirements is demonstrated through plant procedures and reactivity analyses performed for reload specific refueling activities.

4.3.2.7 Stability

See Appendix A, subsection A.4.3.2.7 of Reference 4.3-4.

4.3.2.7.1 Xenon Transients

See Appendix A, subsection A.4.3.2.7.1 of Reference 4.3-4.

4.3.2.7.2 Thermal Hydraulic Stability

See Appendix A, subsection A.4.3.2.7.2 of Reference 4.3-4.

4.3.2.8 Vessel Irradiations

The reactor pressure vessel (RPV) irradiation calculation provides a best-estimate prediction of the fluence rather than a conservative prediction as was the case with earlier methods. The methodology for the neutron flux calculation conforms to Licensing Topical Report (LTR) NEDC-32983-P-A (Reference 4.3-10). In general, the methodology described in the LTR adheres to the guidance in Regulatory Guide 1.190 for neutron flux evaluation and was approved by the U.S. NRC in the Safety Evaluation Report (SER) for referencing in licensing actions.

The fluence calculations are performed with the DORTG01V discrete ordinates transport code. The LTR provides a description of the DORT calculation used to determine the RPV fluence, as well as the calculations used to predict the measured dosimetry and validate the transport model. The calculational model includes a representation of the peripheral fuel assemblies and the core-internals, downcomer and vessel geometry. Calculations are performed to determine the bundle-average power distribution in the peripheral fuel bundles for input to the DORT core neutron source. Calculations employ a relatively fine (r, θ, z) spatial mesh and are carried out using an S_{12} angular quadrature set. The eighty-group MATXS cross section library is the basic nuclear data set. The cross section data used in these calculations is based on the ENDF/B-V nuclear data except for iron, hydrogen and oxygen. Since the cross sections for these elements have changed significantly in the more recent ENDF/B-VI data set, ENDF/B-VI cross sections were used for oxygen, hydrogen, and individual iron isotopes. The cross section library is used in performing the energy and spatial self-shielding and removal

calculations. The scattering cross sections are represented using a P_3 Legendre expansion. The calculations are performed in azimuthal (r, θ) and axial (r, z) geometries. A synthesis technique is used to determine the three-dimensional fluence distribution.

Figure 4.3-1 shows a quadrant of the core and the vessel internal components that are relevant to the flux calculation (Reference 4.3-5). The reactor core is divided into three radial zones, based on the geometric layout of the bundles and their relative contribution to the shroud and RPV flux. The (r, θ) analysis used the polar coordinates to define the calculation model as a planar sector between pre-selected reactor azimuths (typically 0° and 90°). Since the surveillance capsule is centered close to the midplane elevation of the core, core midplane data is assumed for the analysis. The model includes several material regions radially: three in-core regions, the bypass water region, shroud, downcomer water, jet-pump riser, jet-pump inlet mixer, surveillance capsule holder/bracket, and the RPV cladding and base metal.

The core model for the axial (r,z) calculation is a cylinder simulating the cross-sectional area of the core at a pre-selected azimuth. For the capsule flux calculation, the (r,z) calculation was performed at the 300° azimuth, where the capsule is located. For the shroud/RPV flux calculation, the azimuth of 24° was selected because it is near the peak shroud flux and peak RPV flux. The core cylinder contains the afore-mentioned three radial zones for each of the 25 axial fuel nodes. Each axial fuel node is sub-divided into bundle-dependent radial regions so that each core region is modeled with its respective water density, structure material density, and actinide concentration. Similar to the (r, θ) model, there are bypass water, shroud, downcomer water, and RPV regions beyond the core.

Table 4.3-1 summarizes the neutron fluence results (Reference 4.3-5). Two sets of fluence data are presented: at the end of 40 years (33.1 EFPY), and at the end of 60 years (51.6 EFPY). Note EFPY is defined as 3323 MWt based effective full power years. The calculation of 33.1 EFPY factors in the uprated power (3486 MWt) from Cycle 11 through end of life (Reference 4.3-5). Fluence projections after Cycle 17 include a 10% adder to bound potential variation in future cycles.

Note: Columbia Generating Station is evaluated for a fluence that bounds the required value for operation at 3544 MWt from cycle 24 through the end of life (Reference 4.3-14).

The RPV peak fluence (at 33.1 EFPY) given in Table 4.3-1 is used for development of the P-T limit curves. The peak 1/4 T fluence values (n/cm^2) used for P-T curve development are: 1.75E+17 for lower shell #1, 5.11E+17 for lower-intermediate shell #2, 2.81E+17 for N6 nozzle and 2.13E+17 for girth weld between shell #1 and shell #2 (Reference 4.3-6). The 1/4 T fluences were calculated in accordance with RG 1.99, Revision 2.

4.3.3 ANALYTICAL METHODS

See Appendix A, subsection A.4.3.3 of Reference 4.3-4.

4.3.4 CHANGES

See Appendix A, subsection A.4.3.4 of Reference 4.3-4.

4.3.5 REFERENCES

4.3-1 "GNF2 Advantage Generic compliance with NEDE-24011-P-A (GESTAR II)," NEDC-33270P, (most recent version referenced in COLR).

4.3-2 "GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," NEDC-32868P, (most recent version referenced in COLR).

4.3-3 Reference Loading Pattern (most recent version referenced in COLR).

4.3-4 General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A, and Supplement for United States, NEDE-24011-P-A-US (most recent approved version referenced in COLR).

4.3-5 GE Nuclear Energy, Washington Public Power Supply System WNP-2 RPV Surveillance Materials Testing and Analysis, Document No. GE-NE-B1301809-01, March 1997.

GE Nuclear Energy, "Energy Northwest Columbia Generating Station Neutron Flux Evaluation," GE-NE-0000-0023-5057-R0, April 2004.

4.3-6 GE Nuclear Energy, "Pressure-Temperature Curves for Energy Northwest Columbia," NEDC-33144-P (CVI CAL 1012-00,3).

4.3-7 Supplemental Reload Licensing Report for Columbia (most recent version referenced in COLR).

4.3-8 Fuel Bundle Information Report for Columbia (most recent version referenced in COLR).

4.3-9 "Global Nuclear Fuels Fuel Bundle Designs," NEDE-31152P, Revision 9, May 2007.

4.3-10 GE Nuclear Energy, "Licensing Topical Report, General Electric Methodoloty for Reactor Pressure Vessel Fast Neutron Flux Evaluations," NEDC-32983-P-A, Revision 2, January 2006.

4.3-11 Deleted.

4.3-12 GE Nuclear Energy, Washington Public Power Supply System Nuclear Project 2, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, September 1993.

4.3-13 GE Nuclear Energy, "Licensing Topical Report, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations," NEDC-32983-P-A, December 2001.

4.3-14 GE-Hitachi Nuclear Energy, "Safety Analysis Report for Columbia Generating Station Thermal Power Optimization," NEDC-33853P, March 2016.

Table 4.3-1

Summary of Neutron Fluence Results

	Flux (n/cm^2-s)		Fluence (n/cm^2)	
	Cycle 10	Representative Future Cycle	40-year (33.1 EFPY)*	60-year (51.6 EFPY)*
RPV				
At Midplane	6.92E+08	5.75E+08	6.77E+17	1.03E+18
At Peak Elevation	7.60E+08	6.27E+08	7.41E+17	1.12E+18
Peak/Midplane	1.10	1.09	1.09	1.09
Elevation for 10^{17} fluence (inches above BAF)				
Bottom			-3.3	-7.0
Top			156.2	160.0
Shroud				
At Midplane	1.81E+12	1.54E+12	1.80E+21	2.75E+21
At Peak Elevation	2.07E+12	1.73E+12	2.02E+21	3.06E+21
Peak/Midplane	1.15	1.12	1.12	1.11
Top Guide	2.08E+13	1.91E+13	2.15E+22	3.31E+22
Core Plate	3.39E+11	3.04E+11	3.46E+20	5.31E+20

* EFPY is defined as 3323 MWt based effective full power years. The calculation of 33.1 and 51.6 EFPY factors in the uprated power (3486 MWt) from Cycle 11 through End of Life (Reference 4.3-5).

Note: Columbia Generating Station is evaluated for a fluence that bounds the required value for operation at 3544 MWt from cycle 24 through the end of life (Reference 4.3-14).

Table 4.3-2

Reload Fuel Neutronic Design Values

	GE14 & GNF2[1]
Fuel pellet	
Fuel material	
Density, g/cm^3 % of T.D.	
Diameter	
Enriched fuel	
Natural fuel	
Fuel rod	
Fuel length, full, in.	
Fuel length, partial, in.	
Cladding material	
Clad I.D., in.	
Clad O.D., in.	
Fuel assembly	
Number of fuel rods, full length	
Number of fuel rods, partial length	
Number of inert water rods	
Fuel rod enrichments	Reference 4.3-8
Fuel rod pitch, in.	
Fuel assembly loading, kg uranium	Reference 4.3-8

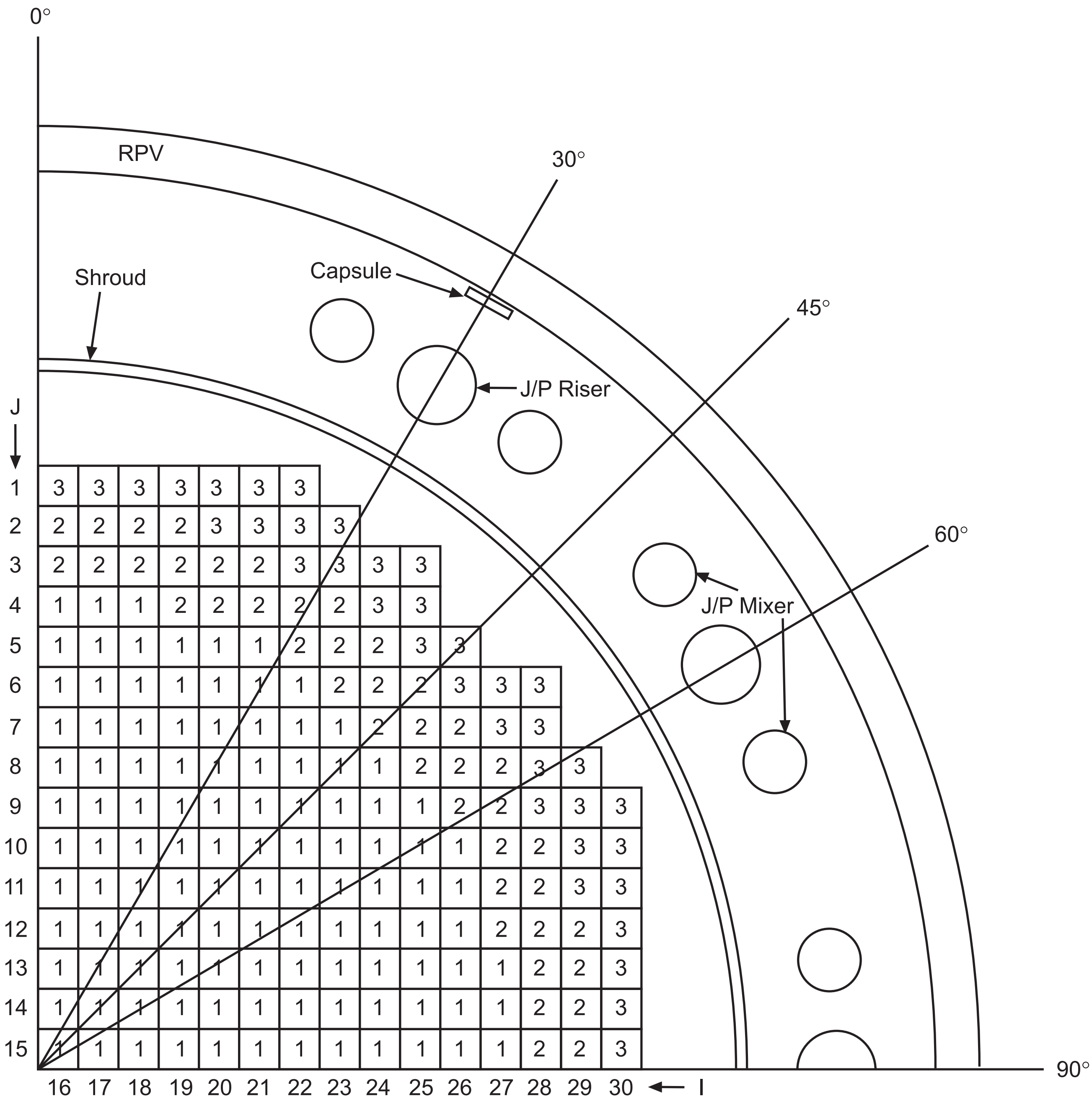
[1] GNF2 and GE14 design values are provided in Table 2-1 of Reference 4.3-1.

Table 4.3-3

Neutronic Design Values

Parameter	Value
Core data	
Number of fuel assemblies	764
Rated power, MWt	3544
Rated core flow, Mlbm/hr	108.5
Core inlet enthalpy, Btu/lbm	528.5
Reactor dome pressure, psia	1035
Fuel assembly pitch, in.	6.00
Control rod data[a]	
Absorber material	B_4C
Total blade span, in.	9.75
Total blade support span, in.	1.58
Blade thickness	0.260
Blade face-to-face internal dimension, in.	0.200
Absorber rods per blade	76
Absorber rods outside diameter, in.	0.188
Absorber rods inside diameter, in.	0.138
Absorber density, % of theoretical	70.0

[a] Original equipment control rods. Some of the control blades are replaced with Duralife 215 and Marathon control blades.



Columbia Generating Station Final Safety Analysis Report	**Core Layout and Vessel Internal Components**
	Draw. No. **960690.10** | Rev. | Figure **4.3-1**

4.4 THERMAL-HYDRAULIC DESIGN

4.4.1 DESIGN BASES

4.4.1.1 Safety Design Bases

See Appendix A, subsection A.4.4.1.1 of Reference 4.4-1.

4.4.1.2 Requirements for Steady-State Conditions

See Appendix A, subsection A.4.4.1.2 of Reference 4.4-1.

For purposes of maintaining adequate thermal margin during normal steady-state operation, the minimum critical power ratio (MCPR) must not be less than the required MCPR operating limit, and the maximum linear heat generation rate (MLHGR) must be maintained below the design linear heat generation rate (LHGR) for the plant. This does not specify the operating power nor does it specify peaking factors. These parameters are determined subject to a number of constraints including the thermal limits given previously. The core and fuel design basis for steady-state operation (i.e., MCPR and LHGR limits) have been defined to provide margin between the steady-state operating conditions and any fuel damage condition to accommodate uncertainties and to ensure that no fuel damage results even during the worst anticipated transient condition at any time in life.

4.4.1.3 Requirements for Anticipated Operational Occurrences (AOOs)

See Appendix A, subsection A.4.4.1.3 of Reference 4.4-1.

4.4.1.4 Summary of Design Bases

See Appendix A, subsection A.4.4.1.4 of Reference 4.4-1, and Reference 4.4-4.

4.4.2 DESCRIPTION OF THERMAL-HYDRAULIC DESIGN OF REACTOR CORE

See Appendix A, subsection A.4.4.2 of Reference 4.4-1.

4.4.2.1 Summary Comparison

An evaluation of plant performance from a thermal and hydraulic standpoint is provided in Section 4.4.3. A tabulation of thermal and hydraulic parameters of the core is given in Table 4.4-1.

4.4.2.2 Critical Power Ratio

See Appendix A, subsection A.4.4.2.2 of Reference 4.4-1, Reference 4.2-2 and Reference 4.2-3.

4.4.2.3 Linear Heat Generation Rate

See Appendix A, subsection A.4.4.2.3 of Reference 4.4-1, Reference 4.4-2 and Reference 4.4-3.

4.4.2.4 Void Fraction Distribution

The void fraction exit values are provided in Table 4.4-2.

4.4.2.5 Core Coolant Flow Distribution and Orificing Pattern

Correct distribution of core coolant flow among the fuel assemblies is accomplished by the orifices fixed at the inlet of each fuel assembly in the fuel support pieces. The orifices control the flow distribution and, hence, the coolant conditions within prescribed bounds throughout the design range of core operation. The sizing and design of the orifices ensure stable flow in each fuel assembly during normal operating conditions.

The core is divided into two orifice flow zones. The outer zone is a narrow, reduced-power region around the core periphery. The inner zone is the core central region. No other flow or steam distribution, other than that provided by adjusting power distribution with control rods, is used or needed.

4.4.2.5.1 Flow Distribution Data Comparison

Design core flow calculations were made using the design power distributions. The flow distribution to the fuel assemblies was calculated based on the assumption that the pressure drop across all of the fuel assemblies is the same. This assumption has been confirmed by measuring the flow distribution in BWRs. Therefore, there is a reasonable assurance that the calculated flow distribution throughout the core is in close agreement with the actual flow distribution (Reference 4.4-1).

4.4.2.5.2 Effect of Channel Flow Uncertainties on the MCPR Uncertainty

The channel flow uncertainty has been inherently considered in its contribution to the MCPR uncertainty when evaluating the probability of a fuel rod subject to a boiling transition in establishing the safety limit MCPR.

The channel flow uncertainty is not an independent parameter contributing to the MCPR uncertainty. Its effect has been included in evaluating the probability of a boiling transition during a core wide power and flow calculation.

4.4.2.6 Core Pressure Drop and Hydraulic Loads

See Appendix A, subsection A.4.4.2.6 of Reference 4.4-1, Reference 4.4-2 and Reference 4.4-3.

4.4.2.7 Correlation and Physical Data

See Appendix A, subsection A.4.4.2.7 of Reference 4.4-1, Reference 4.4-2 and Reference 4.4-3.

4.4.2.8 Thermal Effects of Operational Transients

See Appendix A, subsection A.4.4.2.8 of Reference 4.4-1, Reference 4.4-2 and Reference 4.4-3.

4.4.2.9 Uncertainties in Estimates

See Appendix A, subsection A.4.4.2.9 of Reference 4.4-1, Reference 4.4-2 and Reference 4.4-3.

4.4.2.10 Flux Tilt Considerations

See Appendix A, subsection A.4.4.2.10 of Reference 4.4-1.

4.4.3 DESCRIPTION OF THE THERMAL AND HYDRAULIC DESIGN OF THE REACTOR COOLANT SYSTEM

4.4.3.1 Plant Configuration Data

4.4.3.1.1 Reactor Coolant System Configuration

The reactor coolant system is described in Section 5.4 and shown in isometric perspective in Figure 5.4-1. The piping sizes, fittings, and valves are listed in Table 5.4-2.

4.4.3.1.2 Reactor Coolant System Thermal Hydraulic Data

The steady-state distribution of temperature, pressure, and flow rate for each flow path in the reactor coolant system is shown in Figure 5.1-1.

4.4.3.1.3 Reactor Coolant System Geometric Data

Coolant volumes of regions and components within the reactor vessel are shown in Figure 5.1-2.

Table 4.4-3 provides the flow path length, height, liquid level, minimum elevations, and minimum flow areas for each major flow path volume within the reactor vessel and recirculation loops of the reactor coolant systems.

Table 4.4-4 provides the lengths and sizes of all safety injection lines to the reactor coolant system.

4.4.3.2 Operating Restrictions on Pumps

Expected recirculation pump performance curves are shown in Figures 5.4-2 and 5.4-7. These curves are valid for all conditions with a normal operating range varying from approximately 25% to 105% of rated pump flow.

The pump characteristics, including considerations of net positive suction head (NPSH) requirements, are the same for the conditions of two-pump and one-pump operation as described in Section 5.4.1. Subsection 4.4.3.3 gives the operating limits imposed on the recirculation pumps by cavitation, pump loads, bearing design flow starvation, and pump speed.

4.4.3.3 Power-Flow Operating Map

4.4.3.3.1 Limits for Normal Operation

The power-flow operating map for the power range of operation is shown in Figure 4.4-1. The boundaries of this map are as follows.

a. Natural circulation line: The operating state of the reactor moves along this line for the normal control rod withdrawal sequence in the absence of recirculation pump operation,

b. Maximum Extended Load Line Limit Analysis (MELLLA) Boundary: The line passes through 100% power at 80.7% core flow,

c. Rated power line: Constant 100% power line,

d. ICF line: Constant 106% increased core flow line, and

e. Pump cavitation interlock line: This line is required to protect either the recirculation pumps or the jet pumps from cavitation damage.

4.4.3.3.2 Regions of the Power-Flow Map

a. Region I — This region defines the system startup operational capability with the recirculation pumps and motors being driven by the adjustable speed drives (ASDs). Flow is controlled by the variable speed pump, and power changes during normal startup and shutdown will be in this region;

b. Region II — This is the low power area of the operating map where cavitation can be expected in the recirculation pumps and jet pumps. Operation within this region is precluded by system interlocks that run back the pumps to minimum speed; and

c. Region III — This represents the normal operating zone of the map where power changes can be made by either control rod movement or by core flow changes through use of the variable speed pumps.

4.4.3.3.3 Design Features for Power-Flow Control

The following limits and design features are employed to maintain power-flow conditions to the required values shown in Figure 4.4-1:

a. Minimum power limits at intermediate and high core flows. To prevent cavitation in the recirculation pumps and jet pumps, the recirculating system is provided with an interlock to run back the pump speed to 15 Hz if the difference between steam line temperature and recirculation pump inlet temperature is less than a preset value (10.7°F). This action is initiated electronically through a time delay.

b. Minimum power limit at low core flow. During low power, low loop flow operations, the temperature differential interlock provides cavitation protection. Activation of the temperature differential interlock will run back the pump speed to 15 Hz. The ASD output speed/frequency is measured by instrumentation provided for monitoring the ASD. The speed change action is electronically initiated.

c. Pump bearing limit. For pumps as large as the recirculation pumps, practical limits of pump bearing design require that minimum pump flow be limited to 25% of rated. To ensure this minimum flow, the system is designed so that the minimum pump speed will allow this rate of flow.

d. Valve position. To prevent structural or cavitation damage to the recirculation pump due to pump suction flow starvation, the system is provided with an interlock to prevent starting the pumps or to trip the pumps if the suction or discharge block valves are at less than 90% open position. This circuit is activated by a position limit switch and is active before the pump is started, during individual loop manual control mode, or during ganged loop manual control.

The cavitation limits are established for two-pump operation, but will not protect the jet pumps and recirculation pumps on one-pump operation. Therefore, additional procedural operational limits are established to prevent cavitation damage during the single loop operation. One-pump operation is restricted to the Extended Load Line Limit Analysis (108% rodline) boundary because extended operation in the MELLLA domain has not been evaluated. The procedural operational limits are shown in Figure 4.4-2.

Flow Control. The principal modes of normal operation with ASD flow control are summarized as follows: The recirculation pumps are started when the suction and discharge block valves are full open; with the pump speed at 15 Hz the reactor heatup and pressurization can commence. When operating pressure has been established, reactor power can be increased. This power-flow increase will follow a line within Region I of the flow control map shown in Figure 4.4-1.

When reactor power is greater than approximately 20% of rated, the steam line to recirculation pump inlet differential temperature low feedwater flow interlock is cleared and the main

recirculation pump speed can be manually increased from 15 Hz. The system is then brought to the desired power-flow level within the normal operating area of the map (Region III) by individual loop control or manual ganged control of the ASD system output frequency and by withdrawing control rods.

Recirculation pump speed increases resulting from ASD system output frequency increases toward 63 Hz with constant control rod position will result in power/flow changes along, or nearly parallel to, the 100% rod line.

4.4.3.4 Temperature-Power Operating Map

Not applicable.

4.4.3.5 Load-Following Characteristics

The automatic load following feature has been deleted from the system. All load increases or decreases on CGS are manually controlled by the operator.

4.4.3.6 Thermal and Hydraulic Characteristics Summary Table

The thermal-hydraulic characteristics are provided in Table 4.4-1 for the core and tables of Section 5.4 for other portions of the reactor coolant system.

4.4.4 EVALUATION

See Appendix A, subsections A.4.4.4 – A.4.4.4.5 of Reference 4.4-1, Reference 4.4-2 and Reference 4.4-3.

4.4.4.1 Bypass Flow

Table 4.4-5 shows the bypass flows for the two cases of the GE14 and GNF2 core.

4.4.4.2 Thermal Hydraulic Stability Analysis

Core thermal-hydraulic analyses are performed in accordance with the Long-Term Stability Solutions Option III methodology described in Reference 4.4-1. The analysis supporting the OPRM System Period Based Detection Algorithm (PBDA) setpoints is presented in Reference 4.4-4. A backup stability protection may be used on an interim basis as allowed by Technical Specifications. The analysis supporting the backup stability protection is presented in Reference 4.4-4, and the methods used in the backup stability protection analysis are presented in Reference 4.4-1.

4.4.5 TESTING AND VERIFICATION

See Appendix A, subsection A.4.4.5 of Reference 4.4-1.

4.4.6 INSTRUMENTATION REQUIREMENTS

See Appendix A, subsection A.4.4.6 of Reference 4.4-1.

4.4.6.1 Loose Parts

The instrumentation for online monitoring for loose parts in the reactor vessel has been deactivated.

See Section 7.7.1.12 for further information.

4.4.7 REFERENCES

4.4-1 General Electric Company, General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A, and Supplement for United States, NEDE-24011-P-A-US (most recent approved version referenced in COLR).

4.4-2 "GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II)," NEDC-33270P, (most recent version referenced in COLR).

4.4-3 "GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," NEDC-32868P, (most recent version referenced in COLR).

4.4-4 Supplemental Reload Licensing Report for Columbia (most recent version referenced in COLR).

4.4-9 GEXL97 Correlation Applicable to ATRIUM-10 Fuel, NEDC-33419P, Revision 0, June 2008.

4.4-10 Methodology and Uncertainties for Safety Limit MCPR Evaluations, NEDC-32601P-A, August 1999.

4.4-11 Power Distribution Uncertainties for Safety Limit MCPR Evaluations, NEDC-32694P-A, August 1999.

4.4-12 Fuel Bundle Information Report for Columbia (most recent version referenced in COLR).

Table 4.4-1

Thermal and Hydraulic Design Characteristics
of the Reactor Core

General Operating Conditions	Parameter
Reference design thermal output, MWt	3486
Power level for engineered safety features, MWt	3716
Steam flow rate, at 421.2°F final feedwater temperature, millions lb/hr	15.01
Core coolant flow rate range, millions lb/hr	87.6-115
Feedwater flow rate, millions lb/hr	14.98
System pressure, nominal in steam dome, psia	1035
Core exit pressure, nominal, psia	1047
Coolant saturation temperature at core design pressure, °F	550
Average power density, kW/liter	51.56
Average linear heat generation rate, kW/ft	4.05
Core total heat transfer area, ft^2	86,099
Average heat flux, Btu/hr-ft^2	132,790
Design operating minimum critical power ratio (MCPR)	(see COLR)[a]
Core inlet enthalpy at 421.2°F FFWT, Btu/lb	528.7
Core inlet temperature, at 421.2°F FFWT, °F	533.9
Power assembly exit void fraction, % (RPF=1.0)	71.2
Assembly flow, klbm/hr	120.4[b]
Core pressure drop, psid	23.437[b]

[a] Core Operating Limits Report.

[b] Based on full core of GE14, (1035 psia dome pressure, 3486 MWt) power and 108.5 Mlbm/hr (100% of rated core flow).

Table 4.4-2

Mixed Core Thermal Hydraulic Analysis Results[a]

	GE14	GNF2
Assembly flow (Klb/hr)	109.69	115.12
Exit quality (active region)	0.259	0.259
Exit void fraction	0.824	0.824
Critical power ratio[b]	1.575	1.671

[a] Core ~1/3 GNF2 fuel and 2/3 GE14 fuel
3545 MWt core power and 108.5 Mlbm/hr core flow.
Values for a high power assembly: 1.40 radial peaking factor.

[b] Estimates obtained using the GEXL critical power correlation (References 4.4-2 and 4.4-3).

Table 4.4-3

Reactor Coolant System Geometric Data

	Flow Path Length (in.)	Height and Liquid Level (in.)	Elevation of Bottom of Each Volume[a]	Minimum Flow Areas (ft^2)
Lower plenum	216	216 216	-172.5	71.5
Core	164	164 164	44.0	142.0
Upper plenum and separators	178	178 178	208.0	49.5
Dome (above normal water level)	312	312 0	386.0	343.5
Downcomer area	321	321 321	-51.0	79.5
Recirculation loops and jet pumps (one loop)	108.5 ft	403 403	-394.5	132.5 in^2

[a] Reference point is recirculation nozzle outlet centerline.

Table 4.4-4

Lengths and Sizes of Safety Injection Lines

	Line O.D. (in.)	Line Length (ft)
HPCS line		
Pump discharge to valve[a]	16	319
From HPCS-V-4 inside containment to RPV	12.75	108
Total		427
LPCI lines		
Loop A		
1. Pump discharge to reducer	18	421
2. Reducer to injection valve,[a] RHR-V-42A	14	6
3. From RHR-V-42A to RPV	14	94
Total		521
Loop B		
1. Pump discharge to reducer	18	394
2. Reducer to injection valve RHR-V-42B	14	6
3. Inside containment to RPV	14	93
Total		493
Loop C		
1. Pump discharge to reducer	18	71
2. Reducer to injection valve RHR-V-42C	14	138
3. Inside containment to RPV	14	99
Total		308
LPCS line		
Pump discharge to valve[a]	16	222
Inside containment to RPV	12.75	117
Total		339

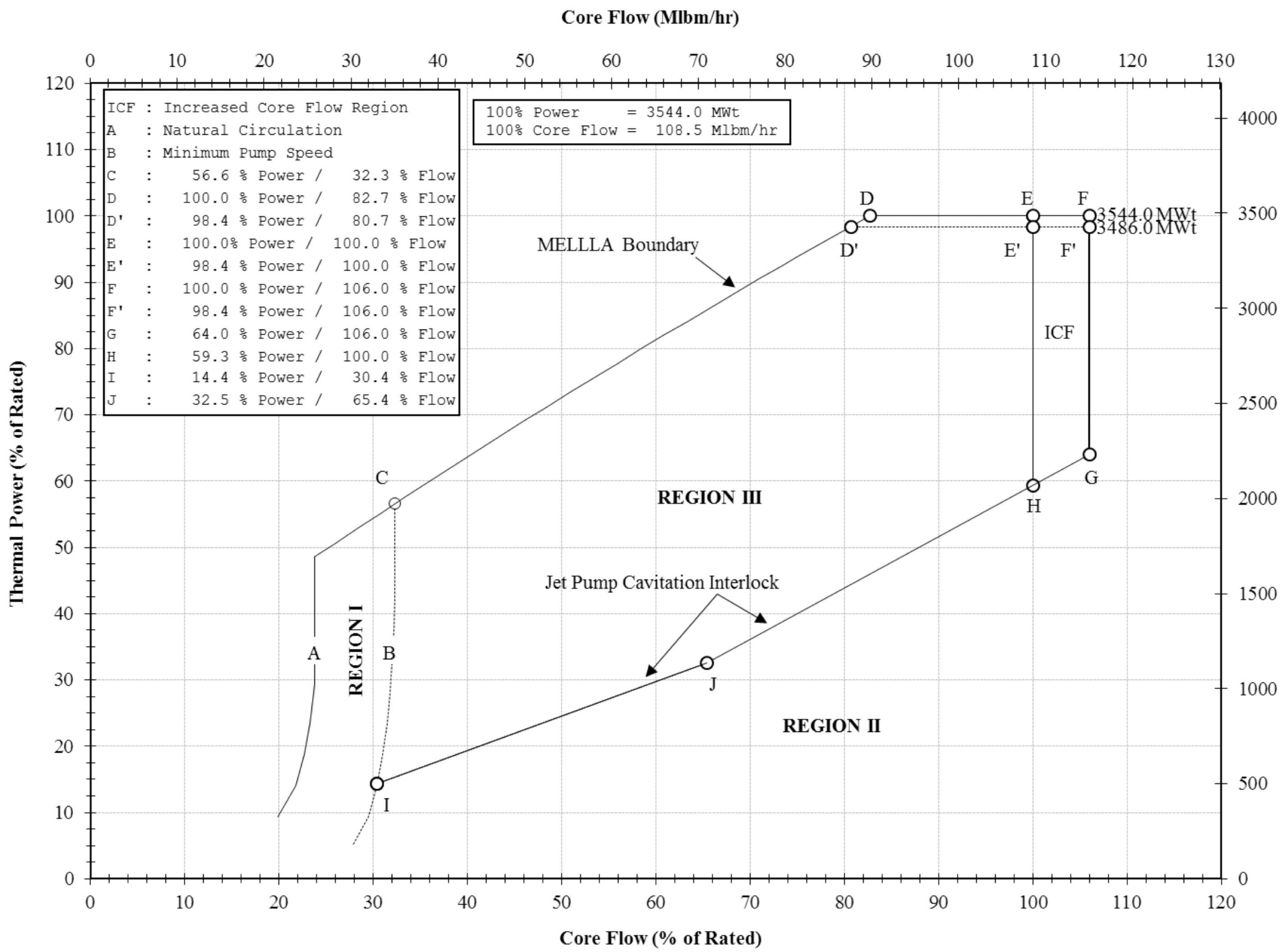
[a] Injection valve located as near as possible to outside of containment wall.

Table 4.4-5 [a,b]

Core Pressure Drop and Leakage Flow
Results for Core Configurations

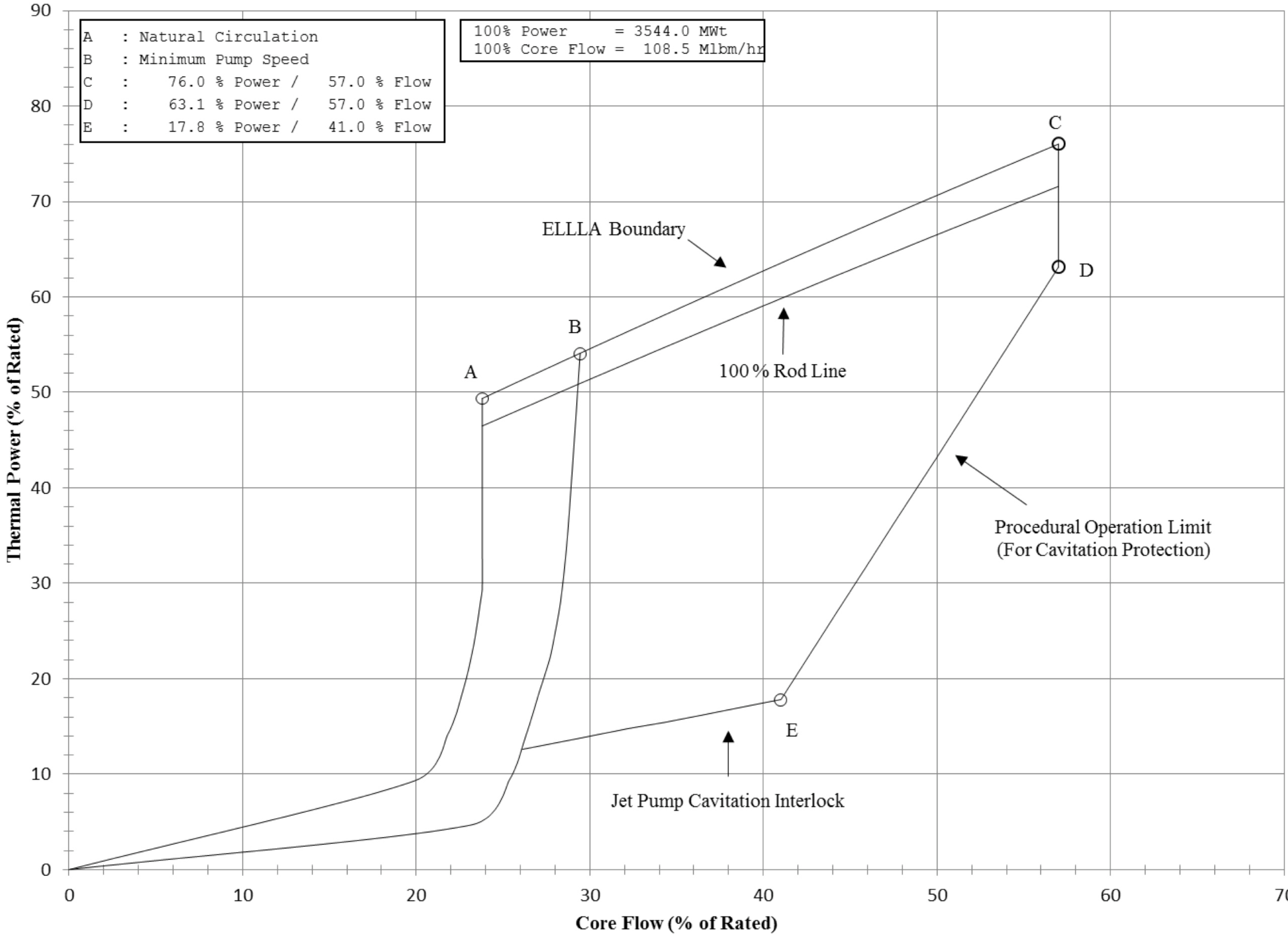
Case	Core Pressure Drop (psid)	Core Bypass Flow (%)
1: All GE14 core	24.403	11.7
2: All GNF2 core	23.626	11.1

[a] Core power: 3545 MWt; core flow: 108.5 Mlb/hr.
[b] Including both leakage flow and water rod flow.



Columbia Generating Station Final Safety Analysis Report	Power-Flow Operating Map Two Loop Operation		
	Draw. No. 960690.03	Rev. 2	Figure 4.4-1

Form No. 960690
LDCN-16-005



Columbia Generating Station Final Safety Analysis Report	Power-Flow Operating Map Single Loop Operation		
	Draw. No. 060108.05	Rev. 2	Figure 4.4-2

4.5 REACTOR MATERIALS

4.5.1 CONTROL ROD SYSTEM STRUCTURAL MATERIALS

4.5.1.1 Material Specifications

The following material listing applies to the control rod drive (CRD) mechanism supplied for this application. The position indicator and minor nonstructural items are omitted.

a. Cylinder, tube, and flange assembly

Flange	ASME SA 182 grade F304
Housing cap screws	ASME SA 540 grade B23, CL4 or SA 193 grade B7
Plugs	ASME SA 182 grade F304
Cylinder	ASTM A269 grade TP 304
Outer tube	ASTM A269 grade TP 304
Tube	ASTM A269 grade TP 304
Spacer	ASTM A269 grade TP 304 or ASTM A511 grade MT 304

b. Piston tube assembly

Piston tube	ASTM A269 grade TP 304 or ASTM A479 grade XM-19
Stud	ASTM A276 type 304
Head/base	ASME SA 182 grade F304
Indicator tube	ASME SA 312 type 316
Cap	ASME SA 182 grade F304 or TP 316

c. Drive assembly

Coupling spud	Inconel X-750
Index tube	ASTM A269 grade TP 304 or ASTM A479 grade XM-19

Piston head	Armco 17-4 PH
Coupling	ASME SA 312 grade TP 304 or ASTM A511 grade MT 304
Magnet housing	ASME SA 312 grade TP 304 or ASTM A511 grade MT 304

d. Collet assembly

Collet piston	ASTM A269 grade TP 304 or ASME SA 312 grade TP 304
Finger	Inconel X-750
Retainer	ASTM A269 grade TP 304 or ASTM A511 grade MT 304
Guide cap	ASTM A269 grade TP 304

e. Miscellaneous parts

Stop piston	ASTM A276 type 304
Connector	ASTM A276 type 304
O-ring spacer	ASME SA 240 type 304
Piston tube nut	ASME SA 194 grade B8 or B8A or SA 479 grade XM-19
Barrel	ASTM A269 grade TP 304 or ASME SA 312 grade TP 304 or ASME SA 240 type 304
Collet spring	Inconel X-750
Ring flange	ASME SA 182 grade F304
Ring flange cap screws	ASME SA 193 grade B6

The materials listed under ASTM specification numbers are all in the annealed condition (with the exception of the outer tube in the cylinder, tube, and flange assembly), and their properties

are readily available. The outer tube is approximately 1/8 hard and has a tensile strength of 90,000/125,000 psi, yield strength of 50,000/85,000 psi, and minimum elongation of 25%.

The coupling spud, collet fingers, and collet spring are fabricated from Inconel X-750 in the annealed or equalized condition and heat treated to produce a tensile strength of 165,000 psi minimum, yield of 105,000 psi minimum, and elongation of 20% minimum. The piston head is Armco 17-4 PH in condition H-1100, with a tensile strength of 140,000 psi minimum, yield of 115,000 psi minimum, and elongation of 15% minimum.

These are widely used materials, whose properties are well known. The parts are readily accessible for inspection and replacement if necessary.

4.5.1.2 Special Materials

No cold-worked austenitic stainless steels with a yield strength greater than 90,000 psi are employed in the CRD system. Armco 17-4 PH (precipitation hardened stainless steel) is used for the piston head. This material is aged to the H-1100 condition to produce resistance to stress corrosion cracking in the BWR environments. Armco 17-4 PH (H-1100) has been successfully used in the past in BWR drive mechanisms. The only hardenable martensitic stainless steel used is the ring flange cap screws. The material is TP 410 in the H-1100 condition.

4.5.1.3 Processes, Inspections, and Tests

All austenitic stainless steel used in the CRD system is solution annealed material with one exception, the outer tube in the cylinder, tube, and flange assembly (see Section 4.5.1.1). Proper solution annealing is verified by testing per ASTM A262, "Recommended Practices for Detecting Susceptibility to Intergranular Attack in Stainless Steels."

Two special processes are employed which subject selected components to temperatures in the sensitization range. These processes are performed on austenitic stainless steel, including XM-19.

a. The cylinder (cylinder, tube, and flange assembly) and the retainer (collet assembly) are hard surfaced with Colmonoy 6.

b. The following components are nitrided to provide a wear resistant surface:

    1. Tube (cylinder, tube, and flange assembly)
    2. Piston tube (piston tube assembly)
    3. Index tube (drive line assembly)
    4. Collet piston and guide cap (collet assembly)

Colmonoy hard-surfaced components have performed successfully in the past in drive mechanisms. Nitrided components have accumulated many years of BWR service. It is normal practice to remove some CRDs periodically during refueling outages. At this time, both the Colmonoy hard-surfaced parts and nitrided surfaces are accessible for visual examination. In addition, dye penetrant examinations have been performed on nitrided surfaces of the longest service drives. This inspection program is adequate to detect any incipient defects before they could become serious enough to cause operating problems.

All austenitic stainless steel is required to be in the solution heat treated condition. Welding is performed in accordance with Section IX of the ASME Boiler and Pressure Vessel (B&PV) Code. Heat input for stainless-steel welds is restricted to a maximum of 50,000 joules/in. and interpass temperature to 350°F. Heating above 800°F (except for welding) is prohibited unless the welds are subsequently solution annealed. These controls are employed to avoid severe sensitization and comply with the intent of Regulatory Guide 1.44.

4.5.1.4 Control of Delta Ferrite Content

All type 308 weld metal is required to comply with a specification which requires a minimum of 5% delta ferrite. This amount of ferrite is adequate to prevent any micro-fissuring (hot cracking) in austenitic stainless steel welds. (See Section 4.5.2.4.)

4.5.1.5 Protection of Materials During Fabrication, Shipping, and Storage

All the CRD parts listed in Section 4.5.1.1 are fabricated under a process specification which limits contaminants in cutting, grinding, and tapping coolants and lubricants. It also restricts all other processing materials (marking inks, tape, etc.) to those which are completely removable by the applied cleaning process. All contaminants are then required to be removed by the appropriate cleaning process prior to any of the following:

a. Any processing which increases part temperature above 200°F,
b. Assembly which results in decrease of accessibility for cleaning, and
c. Release of parts for shipment.

The specification for packaging and shipping the CRD provides for the following:

The drive is rinsed in hot deionized water and dried in preparation for shipment. The ends of the drive are then covered with a vapor tight barrier with desiccant. Packaging is designed to protect the drive and prevent damage to the vapor barrier. The planned storage period considered in the design of the container and packaging is 2 years. This packaging has been in use for a number of years. Periodic audits have indicated satisfactory protection.

The degree of surface cleanliness required by these procedures meets the requirements of Regulatory Guide 1.37.

Site or warehouse storage specifications require inside heated storage comparable to level B of ANSI 45.2.2. After the second year, a yearly inspection of 10% of the humidity indicators (packaged with the drives) is required to verify that the units are dry.

4.5.2 REACTOR INTERNAL MATERIALS

4.5.2.1 Material Specifications

Materials used for the core support structure:

a. Shroud support - Nickel chrome iron alloy, ASME SB166 or SB168,

b. Shroud, core plate (and aligners), top guide (and aligners), and internal structures welded to these components, ASME SA240, SA182, SA479, SA312, SA249, or SA213 (all type 304, except the shroud which is 304L),

c. Peripheral fuel supports - SA312 type 304,

d. Core plate studs and nuts. SA193 grade B8, SA194 grade 8 (all type 304),

e. Control rod drive housing. ASME SA312 type 304, SA182 type 304,

f. Control rod drive guide tube. ASME SA351 type CF8, SA358. SA312, SA249 (type 304), and

g. Orificed fuel support. ASME SA351 type CF8.

Materials used in the steam separators and steam dryers:

a.	All materials are type 304 stainless steel,	
b.	Plate, sheet, and strip	ASTM A240, type 304,
c.	Forgings	ASTM A182, grade F304,
d.	Bars	ASTM A479, type 304,
e.	Pipe	ASTM A312, grade TP 304,
f.	Tube	ASTM A269, grade TP 304,
g.	Bolting material	ASTM A193, grade B8,
h.	Nuts	ASTM A194, grade 8, and
i.	Castings	ASTM A351, grade CF8.

Materials used in the jet pump assemblies:

The components in the jet pump assemblies are a riser, restrainer brackets, inlet-mixers, slip joint clamps, diffusers, and a riser brace. Materials used for these components are to the following specifications:

a.	Castings	ASTM A351 grade CF 8 and ASME SA351 grade CF3,
b.	Bars	ASTM A276 type 304 and ASTM A370 grade E38 and E55,
c.	Bolts	ASTM A193 grade B8 or B8M,
d.	Sheet and plate	ASTM A240 type 304, ASTM A276 type 304, ASTM A358, and ASME SA240 type 304L,
e.	Tubing	ASTM A269 grade TP 304,
f.	Pipe	ASTM A358 type 304 and ASME SA312 grade TP 304,
g.	Welded fittings	ASTM A403 grade WP304, and
h.	Forgings	ASME SA182 grade F304, ASTM B166, and ASTM A637 grade 688.

Materials in the jet pump assemblies which are not type 304 stainless steel are listed below:

a. The inlet mixer adapter casting, the wedge casting, bracket casting adjusting screw casting, and the diffuser collar casting are type 304 hard-surfaced with Stellite 6 for slip fit joints;

b. The diffuser is a bimetallic component made by welding a type 304 forged ring to a forged Inconel 600 ring, made to Specification ASTM B166;

c. The inlet-mixer contains a pin, inserts and beam made of Inconel X-750 to Specification ASTM B637 grade UNS N07750 (Beam), and ASTM A370 grade E38 and E55 (pin and insert);

d. The jet pump beam bolt is type 316L stainless steel;

e. The jet pump slip joint clamp body is fabricated from solution heat-treated ASTM A-182/ASME SA-182 Grade F XM-19 stainless steel with a maximum of 0.04% carbon;

f. The jet pump slip joint clamp adjustable bolt, bolt retainer, pins, and ratchet lock spring are fabricated from ASTM B-637/ASME SB-637 UNS N07750 Type 3 (Alloy X-750); and

g. All components of jet pump restrainer bracket auxiliary wedge assemblies are fabricated from ASTM B-637 UNS N07750 Type 3 (Alloy X-750), except for the frame.

All core support structures are fabricated from ASME specified materials and designed using ASME Code Section III, Appendix I allowable stresses, and ASME Code Section III, Class I, reactor vessel design rules as guides. The other reactor internals are fabricated from ASTM specification materials. Material requirements in the ASTM specifications are identical to requirements in corresponding ASME material specifications. The allowable stress levels specified in ASME Code Section III, Appendix I, are used as a guide in the design of all internal structures in the reactor.

4.5.2.2 Controls on Welding

For core support structures and other internals, weld procedures and welders are qualified in accordance with the ASME B&PV Code, Section IX.

4.5.2.3 Nondestructive Examination of Wrought Seamless Tubular Products

Wrought seamless tubular products are used in the fabrication of the CRD housing. This ASME Code Section III component is designed to the rules of Subsection NB, and the material specified is ASME SA-312 supplemented by GE specifications which invoke Subsection NB requirements. This material meets the requirements of NB-2550 and meets the intent of Regulatory Guide 1.66. The CRD housings are built to the 1971 Edition, Summer 1971 Addenda of the code.

Other internal non-code safety and non-safety components are optionally fabricated from wrought seamless tubular products. This material is supplied in accordance with the applicable ASTM material specifications and is nondestructively examined to the extent specified therein. In addition, the specification for tubular products employed for CRD housings external to the reactor pressure vessel (RPV) meet requirements of paragraph NB-2550 which meets the intent of Regulatory Guide 1.66.

Other internals are non-coded, and wrought seamless tubular products were supplied in accordance with the applicable ASTM material specifications. These specifications require a hydrostatic test on each length of tubing.

4.5.2.4 Fabrication and Processing of Austenitic Stainless Steel - Regulatory Guide Conformance

Regulatory Guide 1.31, Control of Stainless Steel Welding

All austenitic stainless steel weld filler materials were supplied with a minimum of 5% delta ferrite. This amount of ferrite is considered adequate to prevent micro-fissuring in austenitic stainless steel welds. An extensive test program performed by General Electric Company, with the concurrence of the Regulatory Staff, has demonstrated that controlling weld filler metal ferrite at 5% minimum produces production welds which meet the requirements of Regulatory Guide 1.31. A total of approximately 400 production welds in five BWR plants were measured and all welds met the requirements of the Interim Regulatory Position to Regulatory Guide 1.31.

Regulatory Guide 1.34, Control of Electroslag Weld Properties.

Electroslag welding is not employed for any reactor internals.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel.

Nonmetallic thermal insulation is not employed for any components in the reactor vessel. For external applications, all nonmetallic insulation meets the requirements of Regulatory Guide 1.36.

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

All wrought austenitic stainless steel was solution heat treated. Heating above 800°F was prohibited (except for welding) unless the stainless steel was subsequently solution annealed. Purchase specifications restricted the maximum weld heat input to 110,000 joules per in., and the weld interpass temperature to 350°F maximum. Welding was performed in accordance with Section IX of the ASME B&PV Code Section IX. These controls were employed to avoid severe sensitization and comply with the intent of Regulatory Guide 1.44.

Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility

Welder qualification for areas of limited accessibility is discussed in Sections 1.8.2 and 1.8.3.

4.5.2.5 Contamination, Protection, and Cleaning of Austenitic Stainless Steel

Exposure to contaminant was avoided by carefully controlling all cleaning and processing materials which contact stainless steel during manufacture and construction. Any inadvertent surface contamination was removed to avoid potential detrimental effects.

Special care was exercised to ensure removal of surface contaminants prior to any heating operation. Water quality for rinsing, flushing, and testing was controlled and monitored.

The degree of cleanliness required by these procedures meets the requirements of Regulatory Guide 1.37.

4.5.3 CONTROL ROD DRIVE HOUSING SUPPORTS

The American Institute of Steel Construction (AISC) Manual of Steel Construction, "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," was used in designing the CRD housing support system. However, to provide a structure that absorbs as much energy as practical without yielding, the allowable tension and bending stresses used were 90% of yield and the shear stress used was 60% of yield. These design stresses are 1.5 times the AISC allowable stresses (60% and 40% of yield, respectively).

For purposes of mechanical design, the postulated failure resulting in the highest forces is an instantaneous circumferential separation of the CRD housing from the reactor vessel, with the reactor at an operating pressure of 1086 psig (at the bottom of the vessel) acting on the area of the separated housing. The weight of the separated housing, CRD, and blade, plus the pressure of 1086 psig acting on the area of the separated housing, gives a force of approximately 32,000 lb. This force is used to calculate the impact force, conservatively assuming that the housing travels through a 1-in. gap before it contacts the supports. The impact force (109,000 lb) is then treated as a static load in design. The CRD housing supports are designed as Seismic Category I equipment in accordance with Section 3.2.

All CRD housing support subassemblies are fabricated of ASTM A36 structural steel, except for the following items:

a.	Grid	ASTM A441,
b.	Disc springs	Schnerr, type BS-125-71-8,
c.	Hex bolts and nuts	ASTM A307, and
d.	6 x 4 x 3/8 tubes	ASTM A500 grade B.

4.6 FUNCTIONAL DESIGN OF REACTIVITY CONTROL SYSTEMS

Functional design of the control rod drive (CRD) system is discussed below. Functional designs of the recirculation flow control system and the standby liquid control (SLC) system are described in Sections 5.4.1 and 9.3.5, respectively.

4.6.1 INFORMATION FOR THE CONTROL ROD DRIVE SYSTEM

4.6.1.1 Control Rod Drive System Design

4.6.1.1.1 Design Bases

4.6.1.1.1.1 Safety Design Bases. The CRD mechanical system meets the following safety design bases:

a. The design provides for a sufficiently rapid control rod insertion that no fuel damage results from any abnormal operating transient.

b. The design includes positioning devices, each of which individually supports and positions a control rod.

c. Each positioning device

   1. Prevents its control rod from initiating withdrawal as a result of a single malfunction,

   2. Is individually operated so that a failure in one positioning device does not affect the operation of any other positioning device, and

   3. Is individually energized when rapid control rod insertion (scram) is signaled so that failure of power sources external to the positioning device does not prevent other positioning devices' control rods from being inserted.

4.6.1.1.1.2 Power Generation Design Basis. The CRD system design provides for positioning the control rods to control power generation in the core.

4.6.1.1.2 Description

The CRD system controls gross changes in core reactivity by incrementally positioning neutron absorbing control rods within the reactor core in response to manual control signals. It is also required to quickly shut down the reactor (scram) in emergency situations by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal. The CRD

system consists of locking piston CRD mechanisms, and the CRD hydraulic system (including power supply and regulation, hydraulic control units (HCUs), interconnecting piping, instrumentation and electrical controls).

4.6.1.1.2.1 Control Rod Drive Mechanisms. The CRD mechanism (drive) used for positioning the control rod in the reactor core is a double-acting, mechanically latched, hydraulic cylinder using water as its operating fluid (see Figures 4.6-1 through 4.6-4). The individual drives are mounted on the bottom head of the reactor pressure vessel (RPV). The drives do not interfere with refueling and are operative even when the head is removed from the RPV.

The drives are also readily accessible for inspection and servicing. The bottom location makes maximum utilization of the water in the reactor as a neutron shield and gives the least possible neutron exposure to the drive components. Using water from the condensate treatment system and/or condensate storage tanks as the operating fluid eliminates the need for special hydraulic fluid. Drives are able to utilize simple piston seals whose leakage does not contaminate the reactor water but provides cooling for the drive mechanisms and their seals.

The drives are capable of inserting or withdrawing a control rod at a slow, controlled rate, as well as providing rapid insertion when required. A mechanism on the drive locks the control rod at 6-in. increments of stroke over the length of the core.

A coupling spud at the top end of the drive index tube (piston rod) engages and locks into a mating socket at the base of the control rod. The weight of the control rod is sufficient to engage and lock this coupling. Once locked, the drive and rod form an integral unit that must be manually unlocked by specific procedures before the components can be separated.

The drive holds its control rod in distinct latch positions until the hydraulic system actuates movement to a new position. Withdrawal of each rod is limited by a seating of the rod in its guide tube. Withdrawal beyond this position to the over-travel limit can be accomplished only if the rod and drive are uncoupled. Withdrawal to the over-travel limit is annunciated by an alarm.

The individual rod indicators, grouped in one control panel display, correspond to relative rod locations in the core. A separate, smaller display is located just below the large display on the vertical part of the benchboard. This display presents the positions of the control rod selected for movement and the other rods in the affected rod group.

For display purposes the control rods are considered in groups of four adjacent rods centered around a common core volume. Each group is monitored by four local power range monitor (LPRM) strings (see Section 7.6.1.4). Rod groups at the periphery of the core may have less than four rods. The small rod display shows the positions, in digital form, of the rods in the

group to which the selected rod belongs. A white light indicates which of the four rods is the one selected for movement.

4.6.1.1.2.2 Drive Components. Figure 4.6-2 illustrates the operating principle of a drive. Figures 4.6-3 and 4.6-4 illustrate the drive in more detail. The main components of the drive and their functions are described below.

4.6.1.1.2.2.1 Drive Piston. The drive piston is mounted at the lower end of the index tube. This tube functions as a piston. The drive piston and index tube make up the main moving assembly in the drive. The drive piston operates between positive end stops, with a hydraulic cushion provided at the upper end only. The piston has both inside and outside seal rings and operates in an annular space between an inner cylinder (fixed piston tube) and an outer cylinder (drive cylinder). Because the type of inner seal used is effective in only one direction, the lower sets of seal rings are mounted with one set sealing in each direction.

A pair of nonmetallic bushings prevents metal-to-metal contact between the piston assembly and the inner cylinder surface. The outer piston rings are segmented step-cut seals with expander springs holding the segments against the cylinder wall. A pair of split bushings on the outside of the piston prevents piston contact with the cylinder wall. The effective piston area for down-travel or withdrawal is approximately 1.2 $in.^2$ versus 4.1 $in.^2$ for up-travel or insertion. This difference in driving area tends to balance the control rod weight and ensures a higher force for insertion than for withdrawal.

4.6.1.1.2.2.2 Index Tube. The index tube is a long hollow shaft made of nitrided stainless steel. Circumferential locking grooves, spaced every 6 in. along the outer surface, transmit the weight of the control rod to the collet assembly.

4.6.1.1.2.2.3 Collet Assembly. The collet assembly serves as the index tube locking mechanism. It is located in the upper part of the drive unit. This assembly prevents the index tube from accidentally moving downward. The assembly consists of the collet fingers, a return spring, a guide cap, a collet housing (part of the cylinder, tube, and flange), and the collet piston.

Locking is accomplished by fingers mounted on the collet piston at the top of the drive cylinder. In the locked or latched position the fingers engage a locking groove in the index tube.

The collet piston is normally held in the latched position by a force of approximately 150 lb supplied by a spring. Metal piston rings are used to seal the collet piston from reactor vessel pressure. The collet assembly will not unlatch until the collet fingers are unloaded by a short, automatically sequenced, drive-in signal. A pressure, approximately 180 psi force, slide the collet up against the conical surface in the guide cap, and spread the fingers out so they do not engage a locking groove.

A guide cap is fixed in the upper end of the drive assembly. This member provides the unlocking cam surface for the collet fingers and serves as the upper bushing for the index tube.

If reactor water is used during a scram to supplement accumulator pressure, it is drawn through a filter on the guide cap.

4.6.1.1.2.2.4 Piston Tube. The piston tube is an inner cylinder, or column, extending upward inside the drive piston and index tube. The piston tube is fixed to the bottom flange of the drive and remains stationary. Water is brought to the upper side of the drive piston through this tube. A buffer shaft, at the upper end of the piston tube, supports the stop piston and buffer components.

4.6.1.1.2.2.5 Stop Piston. A stationary piston, called the stop piston, is mounted on the upper end of the piston tube. This piston provides the seal between reactor vessel pressure and the space above the drive piston. It also functions as a positive end stop at the upper limit of control rod travel. Piston rings and bushings, similar to those used on the drive piston, are mounted on the upper portion of the stop piston. The lower end of the stop piston is threaded on to the top of the piston tube forming a space for a set of spring washers which serve to protect both the drive piston and the stop piston from damage as the drive piston reaches its end of travel. The upper end of the piston tube has a series of orifices which hydraulically dampen the drive piston motion as the inner seals (or buffer seals) slide past them, effectively cutting off the exhaust path for the over-piston water. The high pressures generated in the buffer are confined to the cylinder portion of the stop piston, and are not applied to the stop piston and drive piston seals.

The center tube of the drive mechanism forms a well to contain the position indicator probe. The probe is an aluminum extrusion attached to a cast aluminum housing. Mounted on the extrusion are hermetically sealed, magnetically operated, position indicator switches. The entire probe assembly is protected by a thin-walled stainless steel tube. The switches are actuated by a ring magnet located at the bottom of the drive piston.

The drive piston, piston tube, and indicator tube are all of nonmagnetic stainless steel, allowing the individual switches to be operated by the magnet as the piston passes. Two switches are located at each position corresponding to an index tube groove, thus allowing redundant indication at each latching point. Two additional switches are located at each midpoint between latching points to indicate the intermediate positions during drive motion. Thus, indication is provided for each 3 in. of travel. Duplicate switches are provided for the full-in and full-out positions. Redundant over-travel switches are located at a position below the normal full-out position. Because the limit of down-travel is normally provided by the control rod itself as it reaches the backseat position, the drive can pass this position and actuate the over-travel switches only if it is uncoupled from its control rod. A convenient means is

thus provided to verify that the drive and control rod are coupled after installation of a drive or at any time during plant operation.

4.6.1.1.2.2.6 Flange and Cylinder Assembly. A flange and cylinder assembly is made up of a heavy flange welded to the drive cylinder. A sealing surface on the upper face of this flange forms the seal to the drive housing flange. The seals contain reactor pressure and the two hydraulic control pressures. Teflon coated, stainless steel rings are used for these seals. The drive flange contains the integral ball, or two-way, check (ball-shuttle) valve. This valve directs either the reactor vessel pressure or the driving pressure, whichever is higher, to the underside of the drive piston. Reactor vessel pressure is admitted to this valve from the annular space between the drive and drive housing through passages in the flange.

Water used to operate the collet piston passes between the outer tube and the cylinder tube. The inside of the cylinder tube is honed to provide the surface required for the drive piston seals.

Both the cylinder tube and outer tube are welded to the drive flange. The upper ends of these tubes have a sliding fit to allow for differential expansion.

4.6.1.1.2.2.7 Lock Plug. The upper end of the index tube is threaded to receive a coupling spud. The coupling (see Figure 4.6-1) accommodates a small amount of angular misalignment between the drive and the control rod. Six spring fingers allow the coupling spud to enter the mating socket on the control rod. A plug then enters the spud and prevents uncoupling.

Two means of uncoupling are provided. With the reactor vessel head removed, the lock plug can be raised against the spring force of approximately 50 lb by a rod extending up through the center of the control rod to an unlocking handle located above the control rod velocity limiter. The control rod, with the lock plug raised, can then be lifted from the drive.

The lock plug can also be pushed up from below, if it is desired to uncouple a drive without removing the RPV head for access. In this case, the central portion of the drive mechanism is pushed up against the uncoupling rod assembly, which raises the lock plug and allows the coupling spud to disengage the socket as the drive piston and index tube are driven down.

The control rod is heavy enough to force the spud fingers to enter the socket and push the lock plug up, allowing the spud to enter the socket completely and the plug to snap back into place. Therefore, the drive can be coupled to the control rod using only the weight of the control rod. However, with the lock plug in place, a force in excess of 50,000 lb is required to pull the coupling apart.

4.6.1.1.2.3 Materials of Construction. Factors that determine the choice of construction materials are discussed in the following subsections.

4.6.1.1.2.3.1 Index Tube. The index tube must withstand the locking and unlocking action of the collet fingers. A compatible bearing combination must be provided that is able to withstand moderate misalignment forces. The reactor environment limits the choice of materials suitable for corrosion resistance. The column and tensile loads can be satisfied by an annealed, single phase, nitrogen strengthened, austenitic stainless steel. The wear and bearing requirements are provided by malcomizing the complete tube. To obtain suitable corrosion resistance, a carefully controlled process of surface preparation is employed.

4.6.1.1.2.3.2 Coupling Spud. The coupling spud is made of Inconel 750 that is aged for maximum physical strength and the required corrosion resistance. Because misalignment tends to cause chafing in the semispherical contact area, the part is protected by a thin chromium plating (electrolized). This plating also prevents galling of the threads attaching the coupling spud to the index tube.

4.6.1.1.2.3.3 Collet Fingers. Inconel 750 is used for the collet fingers, which must function as leaf springs when cammed open to the unlocked position. Colmonoy 6 hard facing provides a long-wearing surface, adequate for design life, to the area contacting the index tube and unlocking cam surface of the guide cap.

Experience at some operating boiling water reactors (BWR) indicates that failures can occur in the collet fingers of the CRD mechanism. To resolve this problem, some BWR facilities installed a revised collet retainer design. However, CGS does not have the revised collet retainer design. General Electric (GE) has demonstrated by testing and operating experience that the existing CRDs meet all safety and licensing requirements and are expected to give full life performances. However, as a result of examining operating drives, GE has discovered evidence of intergranular stress corrosion cracking (IGSCC) in some CRD drive components and has made design improvements to preclude IGSCC in the future. The spare parts for CRD components purchased by Energy Northwest incorporate this revised design. Along with the other parts of the drive, the collet retainer tube, piston tube, and index tube will be routinely checked and changed out, if necessary, with the parts incorporating the revised design.

4.6.1.1.2.3.4 Seals and Bushings. Carbon Graphite material is selected for seals and bushings on the drive piston and stop piston. The material is inert, has a low friction coefficient when water-lubricated and is resistant to degradation at high temperatures. The Carbon Graphite material is relatively soft, which is advantageous when an occasional particle of foreign matter reaches a seal. The resulting scratches in the seal reduce sealing efficiency until worn smooth, but the drive design can tolerate considerable water leakage past the seals into the reactor vessel.

4.6.1.1.2.3.5 Summary. All drive components exposed to reactor vessel water are made of austenitic stainless steel except the following:

a. Seals and bushings on the drive piston and stop piston are Carbon Graphite material,

b. All springs and members requiring spring action (collet fingers, coupling spud, and spring washers) are made of Inconel-750,

c. The ball check valve is a Haynes Stellite cobalt-base alloy,

d. Elastomeric O-ring seals are ethylene propylene,

e. Metal piston rings are Haynes 25 alloy,

f. Certain wear surfaces are hard faced with Colmonoy 6,

g. Nitriding by a proprietary new malcomizing process and chromium plating are used in certain areas where resistance to abrasion is necessary, and

h. The drive piston head is made of Armco 17-4 PH.

Pressure containing portions of the drives are designed and fabricated in accordance with requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section III.

4.6.1.1.2.4 Control Rod Drive Hydraulic System. The CRD hydraulic system (Figure 4.6-5) supplies and controls the pressure and flow to and from the drives through hydraulic control units (HCU). The water discharged from the drives during a scram flows through the HCU to the scram discharge volume (SDV). The water discharged from a drive during a normal control rod positioning operation flows through the HCU, the exhaust header, and is returned to the reactor vessel via the HCUs of nonmoving drives. Each CRD has an associated HCU.

4.6.1.1.2.4.1 Hydraulic Requirements. The CRD hydraulic system design is shown in Figures 4.6-5 and 4.6-6. The hydraulic requirements, identified by the function they perform, are as follows:

a. An accumulator hydraulic charging pressure of approximately 1400 to 1500 psig is required. Flow to the accumulators is required only during scram reset or system startup;

b. Drive water header pressure of approximately 260 psi above reactor vessel pressure is required. A flow rate of approximately 4 gpm to insert a control rod and 2 gpm to withdraw a control rod is required;

c. Cooling water to the drives is required at a flow rate of approximately 0.34 gpm per drive unit. (Cooling water to a drive can be interrupted for short periods without damaging the drive);

d. The SDV is sized to receive and contain all the water discharged by the drives during a scram; a minimum volume of 3.34 gal per drive is required (excluding the instrument volume);

e. Purge water flow to the RPV level instrumentation reference leg backfill system at a flow rate from 0.6 gal/hr to 2.4 gal/hr.

4.6.1.1.2.4.2 System Description. The CRD hydraulic systems provide the required functions with the pumps, filter, valves, instrumentation, and piping shown in Figure 4.6-5 and described in the following.

Duplicate components are included, where necessary, to ensure continuous system operation if an inservice component requires maintenance.

4.6.1.1.2.4.2.1 Supply Pump. One supply pump pressurizes the system with water from a condensate supply header, which takes suction from the condensate treatment system and/or condensate storage tanks depending on plant operation. One installed spare pump is provided for standby. A discharge check valve prevents backflow through the nonoperating pump. A portion of the pump discharge flow is diverted through a minimum flow bypass line to the condensate storage tank. This flow is controlled by an orifice and is sufficient to prevent immediate pump damage if the pump discharge is inadvertently closed.

Condensate water is processed by two filters in the system. The normal CRD pump suction flow path includes a 25-μ filter with a 250-μ Y-strainer upstream of the filter. The filtration capacity of these two in-series elements is limited by and therefore characterized by, the 25-μ filter (see Figure 4.6-5).

The filters used on the CRD system are of a rugged design and failure of the filters are not considered likely. Alarms are provided to give an early warning to the operator that maintenance is required.

The only known mode of failure of the filter element is for it to collapse due to high differential pressure. The CRD pump suction filter can withstand a maximum differential pressure of 20 psi and an alarm indicates in the control room high suction filter differential pressure at 8 psi. The filter element is additionally protected and strengthened by a stainless steel, perforated center tube. The CRD pump discharge filter can withstand a maximum differential pressure of 300 psi and an alarm indicates in the control room high differential pressure at 20 psi. The filter element is constructed entirely of stainless steel.

If the CRD systems pump suction and discharge filters were bypassed completely, possible presence of corrosion particles would not affect the reliability of the scram function of the CRD system. The presence of corrosion particles may accelerate wear of the drive components over a period of time. However, such wear is not a safety concern since this degradation in drive performance already occurs during normal rod operations and is detectable.

4.6.1.1.2.4.2.2 Accumulator Charging Pressure. Accumulator charging pressure is established by the discharge pressure of the system supply pump. During scram the scram inlet (and outlet) valves open and permit the stored energy in the accumulators to discharge into the drives. The resulting pressure decrease in the charging water header allows the CRD supply pump to "run out" (i.e., flow rate to increase substantially) into the CRDs via the charging water header. The flow sensing system upstream of the accumulator charging header detects high flow and closes the flow control valve. This action maintains increased flow through the charging water header.

Pressure in the charging header is monitored in the control room with a pressure indicator and low pressure alarm. Charging water header pressure is not essential to successfully scram the plant. Each of the accumulators are prevented from leaking back to the charging water header by a check valve. Therefore, the pressure required to scram each rod is maintained. The integrity and leaktightness of these check valves are routinely tested as part of the surveillance test program. In addition, when the reactor is at rated pressure, no accumulator pressure is necessary to scram the plant.

During normal operation the flow control valve maintains a constant system flow rate. This flow is used for drive flow, drive cooling, and system stability.

4.6.1.1.2.4.2.3 Drive Water Pressure. Drive water pressure required in the drive header is maintained by the drive/cooling water pressure control valve, which is manually adjusted from the control room. A flow rate of approximately 6 gpm (the sum of the flow rate required to insert and withdraw a control rod) normally passes from the drive water pressure stage through two solenoid-operated stabilizing valves (arranged in parallel) and then goes into the cooling water header. The flow through one stabilizing valve equals the drive insert flow; that of the other stabilizing valve equals the drive withdrawal flow. When operating a drive, the required flow is diverted to that drive by closing the appropriate stabilizing valve while at the same time opening the drive directional control and exhaust solenoid valves. Thus, flow through the drive/cooling water pressure control valve is always constant.

Flow indicators in the drive water header and in the line downstream from the stabilizing valves allow the flow rate through the stabilizing valves to be adjusted when necessary. Differential pressure between the reactor vessel and the drive pressure stage is indicated in the control room.

4.6.1.1.2.4.2.4 Cooling Water Header. The cooling water header is located downstream from the drive/cooling water pressure valve. The drive/cooling water pressure control valve is manually adjusted from the control room to produce the required drive/cooling water pressure balance.

The flow through the flow control valve is virtually constant. Therefore, once adjusted, the drive/cooling water pressure control valve will maintain the correct drive pressure and cooling water pressure, independent of reactor vessel pressure. Changes in setting of the pressure control valve are required only to adjust for changes in the cooling requirements of the drives, as drive seal characteristics change with time. A flow indicator in the control room monitors cooling water flow. A differential pressure indicator in the control room indicates the difference between reactor vessel pressure and drive/cooling water pressure. Although the drives can function without cooling water, temperatures above 350°F can result in fluid flashing and measurable delays in scram times. The temperature of each drive is monitored by a temperature recorder.

4.6.1.1.2.4.2.5 Scram Discharge Volume. The CGS SDV header system is designed as a continually expanding path from the 185 individual 0.75-in. scram discharge (withdrawal) lines to one of two integrated scram discharge volume/instrument volume (SDV/IV) systems (one system per approximately half the drives). Each integrated SDV/IV system consists of a continuously downsloping piping run expanding from the SDV (consisting of seven 6-in. Return headers from the individual HCU banks to an 8-in. combined return header) to the 12-in. vertically oriented IV. The only location where blockage need be assumed (piping less than 2-in. diameter) is in the 0.75 in. discharge line from the individual HCU. Blockage here would only cause failure of one control rod to insert. This is an acceptable consequence for a single failure and has been evaluated as part of the plant design basis. The header piping is sized to receive and contain all the water discharged by the drives during a full scram (3.34 gal per drive) independent of the IV.

During normal plant operation each SDV is empty and vented to the atmosphere through its open vent and drain valve. When a scram occurs on a signal from the safety circuit, these vent and drain valves are closed to conserve reactor water. Redundant vent and drain valves are incorporated in the design of the SDV to ensure that no single failure can result in uncontrolled loss of reactor coolant. Lights in the control room indicate the position of these valves.

During a scram, the SDV partly fills with water discharged from above the drive pistons. After scram is completed, the CRD seal leakage from the reactor continues to flow into the SDV until the discharge volume pressure equals the reactor vessel pressure. A check valve in each HCU prevents reverse flow from the scram discharge header volume to the drive. When the initial scram signal is cleared from the reactor protection system (RPS), the SDV signal is overridden with a key lock override switch, and the SDV is drained and returned to atmospheric pressure.

Remote manual switches in the pilot valve solenoid circuits allow the discharge volume vent and drain valves to be tested without disturbing the RPS. Closing the SDV valves allows the outlet scram valve seats to be leak tested by timing the accumulation of leakage inside the SDV.

Two transmitter/level switches (non-indicating) and two transmitter/level indicating switches directly connected to each instrument volume monitor the volume for abnormal water level. They provide redundant and diverse input to the RPS scram function. One transmitter on each instrument volume also provides input for the control room annunciation and control rod withdrawal block function. There are three different actuation levels. At the lowest level, a level switch on each instrument volume actuates to indicate that the volume is not completely empty during post-scram draining or to indicate that the volume starts to fill through leakage accumulation at other times during reactor operation. At the second level, one level switch on each instrument volume produces a rod withdrawal block to prevent further withdrawal of any control rod, when leakage accumulates to half the capacity of the instrument volume. The two level switches and the two level indicating switches on each instrument volume are interconnected (one of each per trip channel) with the RPS and will initiate a reactor scram on high water level while sufficient volume for a full scram still exists within the SDV. To provide diversity for the RPS function the two transmitters per channel use a different sensing operating principle and have a different transmitter manufacturer. The level switches and the level indicating switches in each channel are also from different manufacturers.

In the event of a slow or partial loss of air pressure, the high-level scram setpoint and the SDV/IV system capacity ensure that scram capability is maintained even in the event of maximum inleakage into the SDV prior to a scram. Analysis, assuming the maximum inleakage of 5 gpm and using the actual calculation piston-over area to determine the scram volume requirements, shows that adequate scram discharge volume will remain in the SDV system at the time that a scram is initiated.

A partial loss of air pressure does not result in the uncontrolled release of reactor coolant to the reactor building should all or most of the scram discharge valves lift. When the water buildup reaches scram initiation level in the IV, a scram signal is produced. This will cause the air supply to the vent and drain valves to vent, thereby ensuring that the vent and drain valves close and isolate. For leakage rates that do not result in buildup in the IV, the leak will drain to the reactor building equipment drain system.

4.6.1.1.2.4.3 <u>Hydraulic Control Units</u>. Each HCU furnishes pressurized water, on signal, to a drive unit. The drive then positions its control rod as required. Operation of the electrical system that supplies scram and normal control rod positioning signals to the HCU is described in Section 7.7.1.2.

The basic components in each HCU are manual, pneumatic, and electrical valves; an accumulator, related piping, electrical connections, filters, and instrumentation (see Figures 4.6-5, 4.6-6, and 4.6-7). The components and their functions are described in the following.

4.6.1.1.2.4.3.1 Insert Drive Valve. The insert drive valve 123 is solenoid operated and opens on an insert signal. The valve supplies drive water to the bottom side of the main drive piston.

4.6.1.1.2.4.3.2 Insert Exhaust Valve. The insert exhaust solenoid valve 121 also opens on an insert signal. The valve discharges water from above the drive piston to the exhaust water header.

4.6.1.1.2.4.3.3 Withdraw Drive Valve. The withdraw drive valve 122 is solenoid operated and opens on a withdraw signal. The valve supplies drive water to the top of the drive piston.

4.6.1.1.2.4.3.4 Withdraw Exhaust Valve. The solenoid operated withdraw exhaust valve 120 opens on a withdraw signal and discharges water from below the main drive piston to the exhaust header. It also serves as the settle valve, which opens following any normal drive movement (insert or withdraw) to allow the control rod and its drive to settle back into the nearest latch position.

4.6.1.1.2.4.3.5 Speed Control Units. The insert drive valve and withdraw exhaust valve have a speed control unit. The speed control unit regulates the control rod insertion and withdrawal rates during normal operation. The manually adjustable flow control unit is used to regulate the water flow to and from the volume beneath the main drive piston. A correctly adjusted unit does not require readjustment except to compensate for changes in drive seal leakage.

4.6.1.1.2.4.3.6 Scram Pilot Valves. The scram pilot valves are operated from the RPS. Two scram pilot valves control both the scram inlet valve and the scram exhaust valve. The scram pilot valves are identical, three-way, solenoid-operated, normally energized valves. On loss of electrical signal to the pilot valves, such as the loss of external ac power, the inlet ports close and the exhaust ports open on both valves. The pilot valves (Figure 4.6-5) are arranged so that the trip system signal must be removed from both valves before air pressure can be discharged from the scram valve operators.

This prevents the inadvertent scram of a single drive in the event of a failure of one of the pilot valve solenoids.

4.6.1.1.2.4.3.7 Scram Inlet Valve. The scram inlet valve opens to supply pressurized water to the bottom of the drive piston. This quick opening globe valve is operated by an internal spring and system pressure. It is closed by air pressure applied to the toe of its diaphragm operator. A position indicator switch on this valve energizes a light in the control room as soon as the valve starts to open.

4.6.1.1.2.4.3.8 Scram Exhaust Valve. The scram exhaust valve opens slightly before the scram inlet valve, exhausting water from above the drive piston. The exhaust valve opens faster than the inlet valve because of the higher air pressure spring setting in the valve

operator. A position indicator switch on this valve energizes a light in the control room as soon as the valve starts to open.

4.6.1.1.2.4.3.9 Scram Accumulator. The scram accumulator stores sufficient energy to fully insert a control rod at lower vessel pressures. At higher vessel pressures the accumulator pressure is assisted or supplanted by reactor vessel pressure. The accumulator is a hydraulic cylinder with a free-floating piston. The piston separates the water on top from the nitrogen below. A check valve in the accumulator charging water line prevents loss of water pressure in the event supply pressure is lost.

During normal plant operation the accumulator piston is seated at the bottom of its cylinder. Loss of nitrogen decreases the nitrogen pressure, which actuates a pressure switch and sounds an alarm in the control room.

To ensure that the accumulator is always able to produce a scram, it is continuously monitored for water leakage. A float type level switch actuates an alarm if water leaks past the piston barrier and collects in the accumulator instrumentation block.

4.6.1.1.2.5 Control Rod Drive System Operation. The CRD system performs rod insertion, rod withdrawal, and scram. These operational functions are described below.

4.6.1.1.2.5.1 Rod Insertion. Rod insertion is initiated by a signal from the operator to the insert valve solenoids. This signal causes both insert valves to open. The insert drive valve applies reactor pressure plus approximately 90 psi to the bottom of the drive piston. The insert exhaust valve allows water from above the drive piston to discharge to the exhaust header.

As is illustrated in Figure 4.6-3, the locking mechanism is a ratchet-type device and does not interfere with rod insertion. The speed at which the drive moves is determined by the flow through the insert speed control valve, which is set for approximately 4 gpm for a shim speed (nonscram operation) of 3 in./sec. During normal insertion, the pressure on the downstream side of the speed control valve is 90 psi to 100 psi above reactor vessel pressure. However, if the drive slows for any reason, the flow through, and pressure drop across, the insert speed control valve will decrease; the full differential pressure (260 psi) will then be available to cause continued insertion. With 260 psi differential pressure acting on the drive piston, the piston exerts an upward force of 1040 lb.

4.6.1.1.2.5.2 Rod Withdrawal. Rod withdrawal is by design more involved than insertion. The collet finger (latch) must be raised to reach the unlocked position (see Figure 4.6-3). The notches in the index tube and the collet fingers are shaped so that the downward force on the index tube holds the collet fingers in place. The index tube must be lifted before the collet fingers can be released. This is done by opening the drive insert valves (in the manner described in the preceding paragraph) for approximately 1 sec. The withdraw valves are then opened, applying driving pressure above the drive piston and opening the area below the piston

to the exhaust header. Pressure is simultaneously applied to the collet piston. As the piston raises, the collet fingers are cammed outward, away from the index tube, by the guide cap.

The pressure required to release the latch is set and maintained at a level high enough to overcome the force of the latch return spring plus the force of reactor pressure opposing movement of the collet piston. When this occurs, the index tube is unlatched and free to move in the withdraw direction. Water displaced by the drive piston flows out through the withdraw speed control valve, which is set to give the control rod a shim speed of 3 in./sec. The entire valving sequence is automatically controlled and is initiated by a single operation of the rod withdraw switch.

4.6.1.1.2.5.3 Scram. During a scram the scram pilot valves and scram valves are operated as previously described. With the scram valves open, accumulator pressure is admitted under the drive piston, and the area over the drive piston is vented to the SDV.

The large differential pressure (initially approximately 1500 psi and always several hundred psi, depending on reactor vessel pressure) produces a large upward force on the index tube and control rod. This force gives the rod a high initial acceleration and provides a large margin of force to overcome friction. After the initial acceleration is achieved, the drive continues at a nearly constant velocity. This characteristic provides a high initial rod insertion rate. As the drive piston nears the top of its stroke the piston seals close off the large passage (buffer orifices) in the stop piston tube, providing a hydraulic cushion at the end of travel.

Prior to a scram signal the accumulator in the HCU has approximately 1450-1510 psig on the water side and 1000-1200 psig on the nitrogen side. As the inlet scram valve opens, the full water-side pressure is available at the CRD acting on a 4.1 in.^{2} area. As CRD motion begins, this pressure drops to the gas-side pressure less line losses between the accumulator and the CRD system; at low vessel pressures the accumulator completely discharges with a resulting gas-side pressure of approximately 575 psi. The CRD accumulators are required to scram the control rods when the reactor pressure is low, and the accumulators retain sufficient stored energy to ensure the complete insertion of the control rods in the required time.

The ball check valve in the drive flange allows reactor pressure to supply the scram force whenever reactor pressure exceeds the supply pressure at the drive. This occurs due to accumulator pressure decay and inlet line losses during all scrams at higher vessel pressures. When the reactor is close to or at fully operating pressure, reactor pressure alone will insert the control rod in the required time, although the accumulator does provide additional margin at the beginning of the stroke.

The CRD system provides the following performance at full power operation and with accumulators. The scram insertion time is measured from the instant the scram pilot valve solenoids are deenergized.

Position inserted from fully withdrawn	45	39	25	5
Tech Spec scram insertion time (sec)	0.528	0.866	1.917	3.437

4.6.1.1.2.6 Instrumentation. The instrumentation for both the control rods and CRDs is defined by that given for the manual control system. The objective of the reactor manual control system is to provide the operator with the means to make changes in nuclear reactivity so that reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

The design bases and further discussion are contained in Chapter 7.

4.6.1.2 Control Rod Drive Housing Supports

4.6.1.2.1 Safety Objective

The CRD housing supports prevent any significant nuclear transient if a drive housing breaks or separates from the bottom of the reactor vessel.

4.6.1.2.2 Safety Design Bases

The CRD housing supports shall meet the following safety design bases:

a. Following a postulated CRD housing failure, control rod downward motion shall be limited so that any resulting nuclear transient could not be sufficient to cause fuel damage, and

b. The clearance between the CRD housings and the supports shall be sufficient to prevent vertical contact stresses caused by thermal expansion during plant operation.

4.6.1.2.3 Description

The CRD housing supports are shown in Figure 4.6-8. Horizontal beams are installed immediately below the bottom head of the reactor vessel, between the rows of CRD housings. The beams are supported by brackets welded to the steel form liner of the drive room in the reactor support pedestal.

Hanger rods, approximately 10 ft long and 1.75 in. in diameter, are supported from the beams on stacks of disc springs. These springs compress approximately 2 in. under the design load.

The support bars are bolted between the bottom ends of the hanger rods. The spring pivots at the top and the beveled, loose fitting ends on the support bars prevent substantial bending moment in the hanger rods if the support bars are overloaded.

Individual grids rest on the support bars between adjacent beams. Because a single piece grid would be difficult to handle in the limited work space and because it is necessary that CRDs, position indicators, and in-core instrumentation components be accessible for inspection and maintenance, each grid is designed for in-place assembly or disassembly. Each grid assembly is made from two grid plates, a clamp, and a bolt. The top part of the clamp guides the grid to its correct position directly below the respective CRD housing that it would support in the postulated accident.

When the support bars and grids are installed, a gap of approximately 1 in. at room temperature (approximately 70°F) is provided between the grid and the bottom contact surface of the CRD flange. During system heatup, this gap is reduced by a net downward expansion of the housings with respect to the supports. In the hot operating condition, the gap is approximately 0.25 in.

In the postulated CRD housing failure, the CRD housing supports are loaded when the lower contact surface of the CRD flange contacts the grid. The resulting load is then carried by two grid plates, two support bars, four hanger rods, their disc springs, and two adjacent beams.

For purposes of mechanical design, the postulated failure resulting in the highest forces is an instantaneous circumferential separation of the CRD housing from the reactor vessel, with an internal pressure of 1250 psig (reactor vessel design pressure) acting on the area of the separated housing. The weight of the separated housing, CRD, and blade, plus the pressure of 1250 psig acting on the area of the separated housing, gives a force of approximately 35,000 lb. This force is multiplied by a factor of three for impact, conservatively assuming that the housing travels through a 1-in. gap before it contacts the supports. The total force (105,000 lb) is then treated as a static load in design.

All CRD housing support subassemblies are fabricated of commonly available structural steel, except for the disc springs, which are Schnorr, Type BS-125-71-8.

4.6.2 EVALUATION OF THE CONTROL ROD DRIVES

Safety evaluation of the control rods, CRDs, and CRD housing supports is described below. Further description of control rods is contained in Section 4.2. The evaluation of the effects of pipe breaks on the CRDs may be found in Section 3.6.

4.6.2.1 Control Rods

4.6.2.1.1 Materials Adequacy Throughout Design Lifetime

The adequacy of the materials throughout the design life was evaluated in the mechanical design of the control rods. The primary materials, B_4C powder, hafnium, and type 304 austenitic stainless steel, have been found suitable in meeting the demands of the BWR environment.

4.6.2.1.2 Dimensional and Tolerance Analysis

Layout studies are done to ensure that, given the worst combination of extreme detail part tolerance ranges at assembly, no interference exists which will restrict the passage of control rods.

The italicized information is historical and was provided to support the application for an operating license.

In addition, during initial preoperational testing, an observer who is in direct communication with the control room will observe the operation of each individual control rod and verify that there is no binding or restriction to rod motion and will listen for any scraping or binding noises which may signify rod misalignment. In addition, the function of each CRD line will be measured as indicated by the differential pressure developed across the CRD piston during notch withdrawal. These differential pressure traces will be compared to reference traces to proper operation and the absence of abnormal friction.

4.6.2.1.3 Thermal Analysis of the Tendency to Warp

The various parts of the control rod assembly remain at approximately the same temperature during reactor operation, negating the problem of distortion or warpage. What little differential thermal growth could exist is allowed for in the mechanical design. A minimum axial gap is maintained between absorber rod tubes and the control rod frame assembly for the purpose. In addition, dissimilar metals are avoided to further this end.

4.6.2.1.4 Forces for Expulsion

An analysis has been performed that evaluates the maximum pressure forces which could tend to eject a control rod from the core. The results of this analysis are given in Section 4.6.2.2.2.2. In summary, if the collet were to remain open, which is unlikely, calculations indicate that the steady-state control rod withdrawal velocity would be 2 ft/sec for a pressure-under line break, the limiting case for rod withdrawal.

4.6.2.1.5 Functional Failure of Critical Components

The consequences of a functional failure of critical components have been evaluated and the results are discussed in Section 4.6.2.2.2.

4.6.2.1.6 Precluding Excessive Rates of Reactivity Addition

To preclude excessive rates of reactivity addition, analysis has been performed both on the velocity limiter device and the effect of probable control rod failures (see Section 4.6.2.2.2).

4.6.2.1.7 Effect of Fuel Rod Failure on Control Rod Channel Clearances

The CRD mechanical design ensures a sufficiently rapid insertion of control rods to preclude the occurrence of fuel rod failures that could hinder reactor shutdown by causing significant distortions in channel clearances.

4.6.2.1.8 Mechanical Damage

Analysis has been performed for all areas of the control system showing that system mechanical damage does not affect the capability to continuously provide reactivity control.

In addition to the analysis performed on the CRD (see Sections 4.6.2.2.2 and 4.6.2.2.3) and the control rod blade, the following discussion summarizes the analysis performed on the control rod guide tube.

The guide tube can be subjected to any or all of the following loads:

a. Inward load due to pressure differential,
b. Lateral loads due to flow across the guide tube,
c. Dead weight,
d. Seismic (vertical and horizontal), and
e. Vibration.

In all cases analysis was performed considering both a recirculation line break and a steam line break. These events result in the largest hydraulic loadings on a control rod guide tube.

Two primary modes of failure were considered in the guide tube analysis: exceeding allowable stress and excessive elastic deformation. It was found that the allowable stress limit will not be exceeded and that the elastic deformations of the guide tube never are great enough to cause the free movement of the control rod to be jeopardized.

4.6.2.1.9 Evaluation of Control Rod Velocity Limiter

The control rod velocity limiter limits the free fall velocity of the control rod to a value that cannot result in nuclear system process barrier damage. This velocity is evaluated by the rod drop accident analysis in Chapter 15.

4.6.2.2 Control Rod Drives

4.6.2.2.1 Evaluation of Scram Time

The rod scram function of the CRD system provides the negative reactivity insertion required by safety design basis Section 4.6.1.1.1.1. The scram time shown in the description is adequate as shown by the transient analyses in Chapter 15.

4.6.2.2.2 Analysis of Malfunction Relating to Rod Withdrawal

There are no known single malfunctions that cause the unplanned withdrawal of even a single control rod. However, if multiple malfunctions are postulated, studies show that an unplanned rod withdrawal can occur at withdrawal speeds that vary with the combination of malfunctions postulated. In all cases the subsequent withdrawal speeds are less than that assumed in the rod drop accident analysis as discussed in Chapter 15. Therefore, the physical and radiological consequences of such rod withdrawals are less than those analyzed in the rod drop accident.

4.6.2.2.2.1 Drive Housing Fails at Attachment Weld. The bottom head of the reactor vessel has a penetration for each CRD location. A drive housing is raised into position inside each penetration and fastened by welding. The drive is raised into the drive housing and bolted to a flange at the bottom of the housing. The housing material is seamless, type 304 stainless-steel pipe with a minimum tensile strength of 75,000 psi. The basic failure considered here is a complete circumferential crack through the housing wall at an elevation just below the J-weld.

Static loads on the housing wall include the weight of the drive and the control rod, the weight of the housing below the J-weld, and the reactor pressure acting on the 6-in.-diameter cross-sectional area of the housing and the drive. Dynamic loading results from the reaction force during drive operation.

If the housing were to fail as described, the following sequence of events is foreseen. The housing would separate from the vessel. The CRD and housing would be blown downward against the support structure by reactor pressure acting on the cross-sectional area of the housing and the drive. The downward motion of the drive and associated parts would be determined by the gap between the bottom of the drive and the support structure and by the deflection of the support structure under load. In the current design, maximum deflection is approximately 3 in. If the collet were to remain latched, no further control rod ejection would occur (Reference 4.6-1); the housing would not drop far enough to clear the vessel

penetration. Reactor water would leak at a rate of approximately 220 gpm through the 0.03-in.-diametral clearance between the housing and the vessel penetration.

If the basic housing failure were to occur while the control rod is being withdrawn (this is a small fraction of the total drive operating time) and if the collet were to stay unlatched, the following sequence of events is foreseen. The housing would separate from the vessel. The drive and housing would be blown downward against the CRD housing support. Calculations indicate that the steady-state rod withdrawal velocity would be 0.3 ft/sec. During withdrawal, pressure under the collet piston would be approximately 250 psi greater than the pressure over it. Therefore, the collet would be held in the unlatched position until driving pressure was removed from the pressure-over port.

4.6.2.2.2.2 <u>Rupture of Hydraulic Line(s) to Drive Housing Flange</u>. There are three types of possible rupture of hydraulic lines to the drive housing flange: (1) pressure-under line break; (2) pressure-over line break; and (3) coincident breakage of both of these lines.

4.6.2.2.2.2.1 <u>Pressure-Under Line Break</u>. For the case of a pressure-under line break, a partial or complete circumferential opening is postulated at or near the point where the line enters the housing flange. Failure is more likely to occur after another basic failure wherein the drive housing or housing flange separates from the reactor vessel. Failure of the housing, however, does not necessarily lead directly to failure of the hydraulic lines.

If the pressure-under line were to fail and if the collet were latched, no control rod withdrawal would occur. There would be no pressure differential across the collet piston and, therefore, no tendency to unlatch the collet. Consequently, the associated control rod could not be withdrawn, but if reactor pressure is greater than 600 psig, it will insert on a scram signal.

The ball check valve is designed to seal off a broken pressure-under line by using reactor pressure to shift the check ball to its upper seat. If the ball check valve were prevented from seating, reactor water would leak to the atmosphere. Because of the broken line, cooling water could not be supplied to the drive involved. Loss of cooling water would cause no immediate damage to the drive. However, prolonged exposure of the drive to temperatures at or near reactor temperature could lead to deterioration of material in the seals. Temperature is monitored by a temperature recorder. A second indication would be high cooling water flow.

If the basic line failure were to occur while the control rod is being withdrawn, the hydraulic force would not be sufficient to hold the collet open, and spring force normally would cause the collet to latch and stop rod withdrawal. However, if the collet were to remain open, calculations indicate that the steady-state control rod withdrawal velocity would be 2 ft/sec.

4.6.2.2.2.2.2 <u>Pressure-Over Line Break</u>. The case of the pressure-over line breakage considers the complete breakage of the line at or near the point where it enters the housing flange. If the line were to break, pressure over the drive piston would drop from reactor

pressure to atmospheric pressure. Any significant reactor pressure (approximately 600 psig or greater) would act on the bottom of the drive piston and fully insert the drive. Insertion would occur regardless of the operational mode at the time of the failure. After full insertion, reactor water would leak past the stop piston seals. This leakage would exhaust to the atmosphere through the broken pressure-over line. The leakage rate at 1000 psi reactor pressure is estimated to be 4 gpm nominal but not more than 10 gpm, based on experimental measurements. If the reactor were hot, drive temperature would increase. This situation would be indicated to the reactor operator by the drift alarm, by the fully inserted drive, by a high drive temperature, and by operation of the drywell sump pump.

4.6.2.2.2.2.3 Simultaneous Breakage of the Pressure-Over and Pressure-Under Lines. For the simultaneous breakage of the pressure-over and pressure-under lines, pressures above and below the drive piston would drop to zero, and the ball check valve would close the broken pressure-under line. Reactor water would flow from the annulus outside the drive, through the vessel ports, and to the space below the drive piston. As in the case of pressure-over line breakage, the drive would then insert (approximately 600 psig or greater) at a speed dependent on reactor pressure. Full insertion would occur regardless of the operational mode at the time of failure. Reactor water would leak past the drive seals and out the broken pressure-over line to the atmosphere, as described above. Drive temperature would increase. Indication in the control room would include the drift alarm, the fully inserted drive, and operation of the drywell sump pump.

4.6.2.2.2.3 All Drive Flange Bolts Fail in Tension. Each CRD is bolted to a flange at the bottom of a drive housing. The flange is welded to the drive housing. Bolts are made of AISI-4140 steel, with a minimum tensile strength of 125,000 psi. Each bolt has an allowable load capacity of 15,200 lb. Capacity of the eight bolts is 121,600 lb. As a result of the reactor design pressure of 1250 psig, the major load on all eight bolts is 30,400 lb.

If a progressive or simultaneous failure of all bolts were to occur, the drive would separate from the housing. The control rod and the drive would be blown downward against the support structure. Impact velocity and support structure loading would be slightly less than that for drive housing failure because reactor pressure would act on the drive cross-sectional area only and the housing would remain attached to the reactor vessel. The drive would be isolated from the cooling water supply. Reactor water would flow downward past the velocity limiter piston, through the large drive filter, and into the annular space between the thermal sleeve and the drive. For worst-case leakage calculations, the large filter is assumed to be deformed or swept out of the way so it would offer no significant flow restriction. At a point near the top of the annulus, where pressure would have dropped to 350 psi, the water would flash to steam and cause choke-flow conditions. Steam would flow down the annulus and out the space between the housing and the drive flanges to the drywell. Steam formation would limit the leakage rate to approximately 840 gpm.

If the collet were latched, control rod ejection would be limited to the distance the drive can drop before coming to rest on the support structure. There would be no tendency for the collet to unlatch, because pressure below the collet piston would drop to zero. Pressure forces, in fact, exert 1435 lb to hold the collet in the latched position.

If the bolts failed during control rod withdrawal, pressure below the collet piston would drop to zero. The collet, with 1650-lb return force, would latch and stop rod withdrawal.

4.6.2.2.2.4 Weld Joining Flange to Housing Fails in Tension. The failure considered is a crack in or near the weld that joins the flange to the housing. This crack extends through the wall and completely around the housing. The flange material is forged, type 304 stainless steel, with a minimum tensile strength of 75,000 psi. The housing material is seamless, type 304 stainless steel pipe, with a minimum tensile strength of 75,000 psi. The conventional, full penetration weld of type 308 stainless steel has a minimum tensile strength approximately the same as that for the parent metal. The design pressure and temperature are 1250 psig and 575°F. Reactor pressure acting on the cross-sectional area of the drive; the weight of the control rod, drive, and flange; and the dynamic reaction force during drive operation result in a maximum tensile stress at the weld of approximately 6000 psi.

If the basic flange-to-housing joint failure occurred, the flange and the attached drive would be blown downward against the support structure. The support structure loading would be slightly less than that for drive housing failure because reactor pressure would act only on the drive cross-sectional area. Lack of differential pressure across the collet piston would cause the collet to remain latched and limit control rod motion to approximately 3 in. Downward drive movement would be small; therefore, most of the drive would remain inside the housing. The pressure-under and pressure-over lines are flexible enough to withstand the small displacement and remain attached to the flange. Reactor water would follow the same leakage path described above for the flange-bolt failure, except that exit to the drywell would be through the gap between the lower end of the housing and the top of the flange. Water would flash to steam in the annulus surrounding the drive. The leakage rate would be approximately 840 gpm.

If the basic failure were to occur during control rod withdrawal (a small fraction of the total operating time) and if the collet were held unlatched, the flange would separate from the housing. The drive and flange would be blown downward against the support structure. The calculated steady-state rod withdrawal velocity would be 0.13 ft/sec. Because pressure-under and pressure-over lines remain intact, driving water pressure would continue to the drive, and the normal exhaust line restriction would exist. The pressure below the velocity limiter piston would drop below normal as a result of leakage from the gap between the housing and the flange. This differential pressure across the velocity limiter piston would result in a net downward force of approximately 70 lb. Leakage out of the housing would greatly reduce the pressure in the annulus surrounding the drive. Thus, the net downward force on the drive piston would be less than normal. The overall effect of these events would be to reduce rod

withdrawal to approximately one-half of normal speed. With a 560 psi differential across the collet piston, the collet would remain unlatched; however, it should relatch as soon as the drive signal is removed.

4.6.2.2.2.5 Housing Wall Ruptures. This failure is a vertical split in the drive housing wall just below the bottom head of the reactor vessel. The flow area of the hole is considered equivalent to the annular area between the drive and the thermal sleeve. Thus, flow through this annular area, rather than flow through the hole in the housing, would govern leakage flow. The housing is made of type 304 stainless-steel seamless pipe, with a minimum tensile strength of 75,000 psi. The maximum hoop stress of 11,900 psi results primarily from the reactor design pressure (1250 psig) acting on the inside of the housing.

If such a rupture were to occur, reactor water would flash to steam and leak through the hole in the housing to the drywell at approximately 1030 gpm. Choke-flow conditions would exist, as described previously for the flange-bolt failure. However, leakage flow would be greater because flow resistance would be less; that is, the leaking water and steam would not have to flow down the length of the housing to reach the drywell. A critical pressure of 350 psi causes the water to flash to steam.

No pressure differential across the collet piston would tend to unlatch the collet, but the drive would insert as a result of loss of pressure in the drive housing causing a pressure drop in the space above the drive piston.

If this failure occurred during control rod withdrawal, drive withdrawal would stop, but the collet would remain unlatched. The drive would be stopped by a reduction of the net downward force action on the drive line. The net force reduction would occur when the leakage flow of 1030 gpm reduces the pressure in the annulus outside the drive to approximately 540 psig, thereby reducing the pressure acting on top of the drive piston to the same value. A pressure differential of approximately 710 psi would exist across the collet piston and hold the collet unlatched as long as the operator held the withdraw signal.

4.6.2.2.2.6 Flange Plug Blows Out. To connect the vessel ports with the bottom of the ball check valve, a hole of 0.75-in. diameter is drilled in the drive flange. The outer end of this hole is sealed with a plug of 0.812-in. diameter and 0.25-in. thickness. A full-penetration, type 308 stainless steel weld holds the plug in place. The postulated failure is a full circumferential crack in this weld and subsequent blowout of the plug.

If the weld were to fail, the plug were to blow out, and the collet remained latched, there would be no control rod motion. There would be no pressure differential across the collet piston acting to unlatch the collet. Reactor water would leak past the velocity limiter piston, down the annulus between the drive and the thermal sleeve, through the vessel ports and drilled passage, and out the open plug hole to the drywell at approximately 320 gpm. Leakage calculations assume only liquid flows from the flange. Actually, hot reactor water would flash

to steam, and choke-flow conditions would exist. Thus, the expected leakage rate would be lower than the calculated value.

If this failure were to occur during control rod withdrawal and if the collet were to stay unlatched, calculations indicate that control rod withdrawal speed would be approximately 0.24 ft/sec. Leakage from the open plug hole in the flange would cause reactor water to flow downward past the velocity limiter piston. A small differential pressure across the piston would result in an insignificant driving force of approximately 10 lb, tending to increase withdraw velocity.

A pressure differential of 295 psi across the collet piston would hold the collet unlatched as long as the driving signal was maintained.

Flow resistance of the exhaust path from the drive would be normal because the ball check valve would be seated at the lower end of its travel by pressure under the drive piston.

4.6.2.2.2.7 Ball Check Valve Plug Blows Out. As a means of access for machining the ball check valve cavity, a 1.25-in.-diameter hole has been drilled in the flange forging. This hole is sealed with a plug of 1.31-in. diameter and 0.38-in. thickness. A full-penetration weld, using type 308 stainless steel filler, holds the plug in place. The failure postulated is a circumferential crack in this weld leading to a blowout of the plug.

If the plug were to blow out while the drive was latched, there would be no control rod motion. No pressure differential would exist across the collet piston to unlatch the collet. As in the previous failure, reactor water would flow past the velocity limiter, down the annulus between the drive and thermal sleeve, through the vessel ports and drilled passage, through the ball check valve cage and out the open plug hole to the drywell. The leakage calculations indicate the flow rate would be 350 gpm. This calculation assumes liquid flow, but flashing of the hot reactor water to steam would reduce this rate to a lower value. Drive temperature would rapidly increase.

If the plug failure were to occur during control rod withdrawal (it would not be possible to unlatch the drive after such a failure), the collet would relatch at the first locking groove. If the collet were to stick, calculations indicate the control rod withdrawal speed would be 11.8 ft/sec. There would be a large retarding force exerted by the velocity limiter due to a 35 psi pressure differential across the velocity limiter piston.

4.6.2.2.2.8 Drive/Cooling Water Pressure Control Valve Failure. The pressure to move a drive is generated by the pressure drop of practically the full system flow through the drive/cooling water pressure control valve. This valve is either a motor-operated valve or a standby manual valve; either one is adjusted to a fixed opening. The normal pressure drop across this valve develops a pressure 260 psi in excess of reactor pressure.

If the flow through the drive/cooling water pressure control valve were to be stopped, as by a valve closure or flow blockage, the drive pressure would increase to the shutoff pressure of the supply pump. The occurrence of this condition during withdrawal of a drive at zero vessel pressure will result in a drive pressure increase from 260 psig to no more than 1750 psig. Calculations indicate that the drive would accelerate from 3 in./sec to approximately 6.5 in./sec. A pressure differential of 1670 psi across the collet piston would hold the collet unlatched. Flow would be upward past the velocity limiter piston, but retarding force would be negligible. Rod movement would stop as soon as the driving signal was removed.

Conversely, if the PCV were to fail to a full open position, the cooling water pressure would increase and the drive water pressure would decrease. The resulting cooling water pressure increase could cause control rods to drift inward. The existence of rod drifts would be alarmed to the control room operator for appropriate action. The resulting drop in drive water pressure would make normal control rod notch movements impossible but would not affect the ability of the scram function.

In both of the cases described above, the manually operated bypass PCV in conjunction with the isolation gate valves located upstream and downstream of the PCV would enable the operators to take corrective action.

In conclusion, although the failure to the full open or full closed position of the drive/cooling water PCV will cause perturbation in the CRD system operation, it does not present a safety problem to affect the scram capability of the CRD system.

4.6.2.2.2.9 Ball Check Valve Fails to Close Passage to Vessel Ports. Should the ball check valve sealing the passage to the vessel ports be dislodged and prevented from reseating following the insert portion of a drive withdrawal sequence, water below the drive piston would return to the reactor through the vessel ports and the annulus between the drive and the housing rather than through the speed control valve. Because the flow resistance of this return path would be lower than normal, the calculated withdrawal speed would be 2 ft/sec. During withdrawal, differential pressure across the collet piston would be approximately 40 psi. Therefore, the collet would tend to latch and would have to stick open before continuous withdrawal at 2 ft/sec, could occur. Water would flow upward past the velocity limiter piston, generating a small retarding force of approximately 120 lb.

4.6.2.2.2.10 Hydraulic Control Unit Valve Failures. Various failures of the valves in the HCU can be postulated, but none could produce differential pressures approaching those described in the preceding paragraphs and none alone could produce a high velocity withdrawal. Leakage through either one or both of the scram valves produces a pressure that tends to insert the control rod rather than to withdraw it. If the pressure in the SDV should exceed reactor pressure following a scram, a check valve in the line to the scram discharge header prevents this pressure from operating the drive mechanisms.

4.6.2.2.2.11 Collet Fingers Fail to Latch. The failure is presumed to occur when the drive withdraw signal is removed. If the collet fails to latch, the drive continues to withdraw at a fraction of the normal speed. This assumption is made because there is no known means for the collet fingers to become unlocked without some initiating signal. Because the collet fingers will not cam open under a load, accidental application of a down signal does not unlock them. (The drive must be given a short insert signal to unload the fingers and cam them open before the collet can be driven to the unlock position.) If the drive withdrawal valve fails to close following a rod withdrawal, the collet would remain open and the drive continue to move at a reduced speed.

4.6.2.2.2.12 Withdrawal Speed Control Valve Failure. Normal withdrawal speed is determined by differential pressures in the drive and is set for a nominal value of 3 in./sec. Withdrawal speed is maintained by the pressure regulating system and is independent of reactor vessel pressure. Tests have shown that accidental opening of the speed control valve to the full-open position produces a velocity of approximately 6 in./sec.

The CRD system prevents unplanned rod withdrawal and it has been shown above that only multiple failures in a drive unit and its control unit could cause an unplanned rod withdrawal.

4.6.2.2.2.13 Slow or Partial Loss of Air to the Scram Discharge Valves. The CGS IV is adequately hydraulically coupled to the SDV, i.e., the IV is connected directly to the SDV with piping of a diameter equal to or greater than the diameter of the SDV headers. This allows for direct detection of liquid buildup so that the ability to scram is ensured.

The basis of the instrument volume high level scram setpoint and the SDV/IV physical arrangement provides for scram action before significant SDV reduction occurs which could affect scram capability.

The high-level scram setpoint and the SDV/IV system capacity ensure that scram capability is maintained even in the event of maximum inleakage into the SDV prior to a scram. Analysis, assuming the maximum inleakage of 5 gpm and using the actual calculated piston-over area to determine the scram volume requirements, shows that adequate SDV will remain in the SDV system at the time that a scram is initiated.

The partial loss of air pressure does not result in the uncontrolled release of reactor coolant to the reactor building. The vent and drain valves are spring to close-held open by air. Flow through the valve tends to close it. As air pressure decreases the valves will begin to close to limit coolant inventory loss. When the water buildup reaches scram initiation level in the IV, a scram signal is produced.

This will cause the air supply to the vent and drain valves to vent, thereby ensuring that the vent and drain valves close and isolate. For leakage rates which do not result in buildup in the IV, the leak will drain to the reactor building equipment drain system.

4.6.2.2.3 Scram Reliability

High scram reliability is the result of a number of features of the CRD system. For example

a. Two reliable sources of scram energy are used to insert each control rod: individual accumulators at low reactor pressure, and the reactor vessel pressure itself at power;

b. Each drive mechanism has its own scram and pilot valves so only one drive can be affected if a scram valve fails to open. Two pilot valves are provided for each drive. Both pilot valves must be deenergized to initiate a scram;

c. The RPS and the HCUs are designed so that the scram signal and mode of operation override all others;

d. The collet assembly and index tube are designed so they will not restrain or prevent control rod insertion during scram; and

e. The SDV is monitored for accumulated water and the reactor will scram before the volume is reduced to a point that could interfere with a scram.

4.6.2.2.4 Control Rod Support and Operation

Each control rod is independently supported and controlled as required by the safety design bases.

4.6.2.3 Control Rod Drive Housing Supports

Downward travel of the CRD housing and its control rod following the postulated housing failure equals the sum of these distances: (1) the compression of the disc springs under dynamic loading, and (2) the initial gap between the grid and the bottom contact surface of the CRD flange. If the reactor were cold and pressurized, the downward motion of the control rod would be limited to the spring compression (approximately 2 in.) plus a gap of approximately 1 in. If the reactor were hot and pressurized, the gap would be approximately 0.25 in. and the spring compression would be slightly less than in the cold condition. In either case, the control rod movement following a housing failure is substantially limited below one drive “notch” movement (6 in.). Sudden withdrawal of any control rod through a distance of one drive notch at any position in the core does not produce a transient sufficient to damage any radioactive material barrier.

The CRD housing supports are in place during power operation and when the reactor coolant system is pressurized. If a control rod is ejected during shutdown, the reactor remains subcritical because it is designed to remain subcritical with any one control rod fully withdrawn at any time.

At plant operating temperature, a gap of approximately 0.25 in. exists between the CRD housing and the supports. At lower temperatures the gap is greater. Because the supports do not contact any of the CRD housing except during the postulated accident condition, vertical contact stresses are prevented.

4.6.3 TESTING AND VERIFICATION OF THE CONTROL ROD DRIVES

4.6.3.1 Control Rod Drives

4.6.3.1.1 Testing and Inspection

4.6.3.1.1.1 Development Tests. The development drive (prototype) testing included more than 5000 scrams and approximately 100,000 latching cycles. One prototype was exposed to simulated operating conditions for 5000 hr. These tests demonstrated the following:

a. The drive easily withstands the forces, pressures, and temperatures imposed;

b. Wear, abrasion, and corrosion of the nitrided stainless parts are negligible. Mechanical performance of the nitrided surface is superior to that of materials used in earlier operating reactors;

c. The basic scram speed of the drive has a satisfactory margin above minimum plant requirements at any reactor vessel pressure; and

d. Usable seal lifetimes in excess of 1000 scram cycles can be expected.

4.6.3.1.1.2 Factory Quality Control Tests. Quality control of welding, heat treatment, dimensional tolerances, material verification, and similar factors is maintained throughout the manufacturing process to ensure reliable performance of the mechanical reactivity control components. Some of the quality control tests performed on the control rods, CRD mechanisms, and HCU are listed below:

a. Control rod drive mechanism tests

    1. Pressure welds on the drives are hydrostatically tested in accordance with ASME codes;

2. Electrical components are checked for electrical continuity and resistance to ground;

3. Drive parts that cannot be visually inspected for dirt are flushed with filtered water at high velocity. No significant foreign material is permitted in effluent water;

4. Seals are tested for leakage to demonstrate correct seal operation;

5. Each drive is tested for shim motion, latching, and control rod position indication; and

6. Each drive is subjected to cold scram tests at various reactor pressures to verify correct scram performance.

b. Hydraulic control unit tests

1. Hydraulic systems are hydrostatically tested in accordance with the applicable code;

2. Electrical components and systems are tested for electrical continuity and resistance to ground;

3. Correct operation of the accumulator pressure and level switches is verified;

4. The unit's ability to perform its part of a scram is demonstrated; and

5. Correct operation and adjustment of the insert and withdrawal valves is demonstrated.

4.6.3.1.1.3 Operational Tests. After installation, all rods and drive mechanisms can be tested through their full stroke for operability.

During normal operation each time a control rod is withdrawn a notch, the operator can observe the in-core monitor indications to verify that the control rod is following the drive mechanism. All control rods that are partially withdrawn from the core can be tested for rod-following by inserting or withdrawing the rod one notch and returning it to its original position, while the operator observes the in-core monitor indications.

To make a positive test of control rod to CRD coupling integrity, the operator can withdraw a control rod to the end of its travel and then attempt to withdraw the drive to the over-travel position. Failure of the drive to over-travel demonstrates rod-to-drive coupling integrity.

Hydraulic supply subsystem pressures can be observed from instrumentation in the control room. Scram accumulator pressures can be observed on the nitrogen pressure gages.

4.6.3.1.1.4 Acceptance Tests. Criteria for acceptance of the individual CRD mechanisms and the associated control and protection systems were incorporated in specifications and test procedures covering three distinct phases: (1) pre-installation, (2) after installation prior to startup, and (3) during startup testing.

The pre-installation specification defined criteria and acceptable ranges of such characteristics as seal leakage, friction, and scram performance under fixed test conditions which must be met before the component was shipped.

The after installation, prestartup tests (Section 14.2) included normal and scram motion and were primarily intended to verify that piping, valves, electrical components and instrumentation were properly installed. The test specifications included criteria and acceptable ranges for drive speed, time settings, scram valve response times, and control pressures. These tests were intended more to document system condition than as tests of performance.

As fuel was placed in the reactor, the startup test procedure (Chapter 14) was followed. The tests in this procedure were intended to demonstrate that the initial operational characteristics meet the limits of the specifications over the range of primary coolant temperatures and pressures from ambient to operating.

4.6.3.1.1.5 Surveillance Tests. The surveillance requirements for the CRD system are as follows:

a. Prior to each in-vessel fuel movement during fuel loading sequence, the shutdown margin with the highest worth control rod withdrawn shall be analytically determined to be at least 0.38% $\Delta k/k$ or shall be determined by test to be at least 0.28% $\Delta k/k$;

b. Once within 4 hr after criticality following fuel movement within the RPV or control rod replacement, the shutdown margin with the highest worth control rod withdrawn shall be analytically determined to be at least 0.38% $\Delta k/k$ or shall be determined by test to be at least 0.28% $\Delta k/k$;

c. Each withdrawn control rod shall be exercised one notch (i.e., inserted at least one notch and then may be returned to its original position) at least once every 31 days.

The control rod exercise tests serve as a periodic check against deterioration of the control rod system and also verifies the ability of the CRD to scram. If a rod can be moved with drive pressure, it may be expected to scram since higher pressure is applied during scram;

d. The coupling integrity shall be verified for each withdrawn control rod as follows:

1. When the rod is first withdrawn, observe discernible response of the nuclear instrumentation, and

2. When the rod is fully withdrawn each time, observe that the drive will not go to the over-travel position.

Observation of a response from the nuclear instrumentation during an attempt to withdraw a control rod indicates indirectly that the rod and drive are coupled. The over-travel position feature provides a positive check on the coupling integrity, for only an uncoupled drive can reach the over-travel position;

e. During operation, accumulator pressure and level at the normal operating value shall be verified.

Experience with CRD systems of the same type indicates that weekly verification of accumulator pressure and level is sufficient to ensure operability of the accumulator portion of the CRD system;

f. At the time of each major refueling outage, each operable control rod shall be subjected to scram time tests from the fully withdrawn position.

Experience indicates that the scram times of the control rods do not significantly change over the time interval between refueling outages. A test of the scram times at each refueling outage is sufficient to identify any significant lengthening of the scram times; and

g. A channel functional test of the accumulator leak detectors and a channel calibration of the accumulator pressure detectors, which verifies an alarm setpoint ≥940 psig on decreasing pressure, is performed at least once per 30 months.

4.6.3.1.1.6 Functional Tests. The functional testing program of the CRDs consists of the 5-year maintenance life and the 1.5X design life test programs as described in Section 3.9.4.4.

There are a number of failures that can be postulated on the CRD but it would be very difficult to test all possible failures. A partial test program with postulated accident conditions and imposed single failures is available.

The following tests with imposed single failures have been performed to evaluate the performance of the CRDs under these conditions:

a. Simulated ruptured scram line test,
b. Stuck ball check valve in CRD flange,
c. HCU drive down inlet flow control valve (V122) failure,
d. HCU drive down outlet flow control valve (V120) failure,
e. CRD scram performance with V120 malfunction,
f. HCU drive up outlet control valve (V121) failure,
g. HCU drive up inlet control valve (V123) failure,
h. Cooling water check valve (V138) leakage,
i. CRD flange check valve leakage,
j. CRD stabilization circuit failure,
k. HCU filter restriction,
l. Air trapped in CRD hydraulic system,
m. CRD collet drop test, and
n. CR qualification velocity limiter drop test.

Additional postulated CRD failures are discussed in Sections 4.6.2.2.2.1 through 4.6.2.2.2.12.

4.6.3.2 Control Rod Drive Housing Supports

CRD housing supports are removed for inspection and maintenance of the CRDs. The supports for one control rod can be removed during reactor shutdown, even when the reactor is pressurized, because all control rods are then inserted. When the support structure is reinstalled, it is inspected for correct assembly with particular attention to maintaining the correct gap between the CRD flange lower contact surface and the grid.

4.6.4 INFORMATION FOR COMBINED PERFORMANCE OF REACTIVITY CONTROL SYSTEMS

4.6.4.1 Vulnerability to Common Mode Failures

The two reactivity control systems, the CRD and SLC systems, do not share any instrumentation or components. Thus, a common mode failure of the reactivity systems would be limited to an accident event which could damage essential equipment in the two independent systems.

A seismic event or the postulated accident environments (see Section 3.11) are not considered potential common mode failures since the essential (scram) portions of the CRD system are designed to Seismic Category I standards and to operate as required under postulated accident environmental conditions. The SLC system is also designed to Seismic Category I standards.

No common mode power failure is considered credible. The scram function of the CRD system is "fail-safe" on a loss of power and is designed to override any other CRD function. The SLC system has two independent power supplies to its essential redundant pumps and valves. The power supplies to the SLC system are considered vital and as such are switched to the onsite standby diesels on a loss of normal power sources.

Essential components (including cabling and piping) for the SLC system are separated from essential CRD components in the secondary containment by physical barriers and/or by at least 40 ft of physical separation. The various safety studies performed by the architect-engineer verified that this separation is sufficient to prevent simultaneous failure of the reactivity systems due to pipe break and whip, credible fires, and all potential missiles. The location of the primary components of these systems is shown in Figures 1.2-7 through 1.2-12. The CRD insert and withdrawal lines penetrate at the bottom of the RPV whereas the SLC lines connect to the HPCS line which penetrates the RPV. Protection of the reactivity control systems from postulated events, such as pipe breaks, is discussed in Section 3.6.

A fault tree analysis was completed for both of these systems, and the calculated unreliability is less than 10^{-7}/reactor year. This unreliability is an estimate of the failure to fully insert the control rods into the core, combined with a failure to inject boron into the vessel by the SLC. Failure to insert control rods is defined to be noninsertion of the CRDs in the following manner: 50% in a "checkerboard pattern," 31% in a random pattern, or 4% in a cluster.

4.6.4.2 Accidents Taking Credit for Multiple Reactivity Systems

There are no postulated accidents evaluated in Chapter 15 that take credit for two or more reactivity control systems preventing or mitigating each accident.

4.6.5 EVALUATION OF COMBINED PERFORMANCE

As indicated in Section 4.6.4.2, credit is not taken for multiple reactivity control systems for any postulated accidents in Chapter 15.

4.6.6 ALTERNATE ROD INSERTION SYSTEM

4.6.6.1 System Description

The alternate rod insertion (ARI) system provides an alternate means to scram the control rods which is diverse and independent from the RPS. The ARI system may be actuated either

manually or automatically. The automatic signal to initiate ARI comes from high reactor vessel pressure or low reactor water level. The setpoints for ARI automatic initiation have been chosen such that a normal scram should already have been initiated by the above parameters prior to ARI initiation. The ARI system causes a scram by relieving the scram air header through four sets of solenoid valves. This, in turn, causes the scram inlet and outlet valves to open. The CRD units then insert the control blades to shutdown the reactor.

The ARI system has been designed to ensure that rod motion begins within sufficient time to ensure the ARI design objectives of Reference 4.6-2 are satisfied. These rod movement times are based on plant unique conditions and compliance with ARI design objectives to ensure that plant safety considerations will be met.

4.6.6.2 Alternate Rod Insertion Redundancy

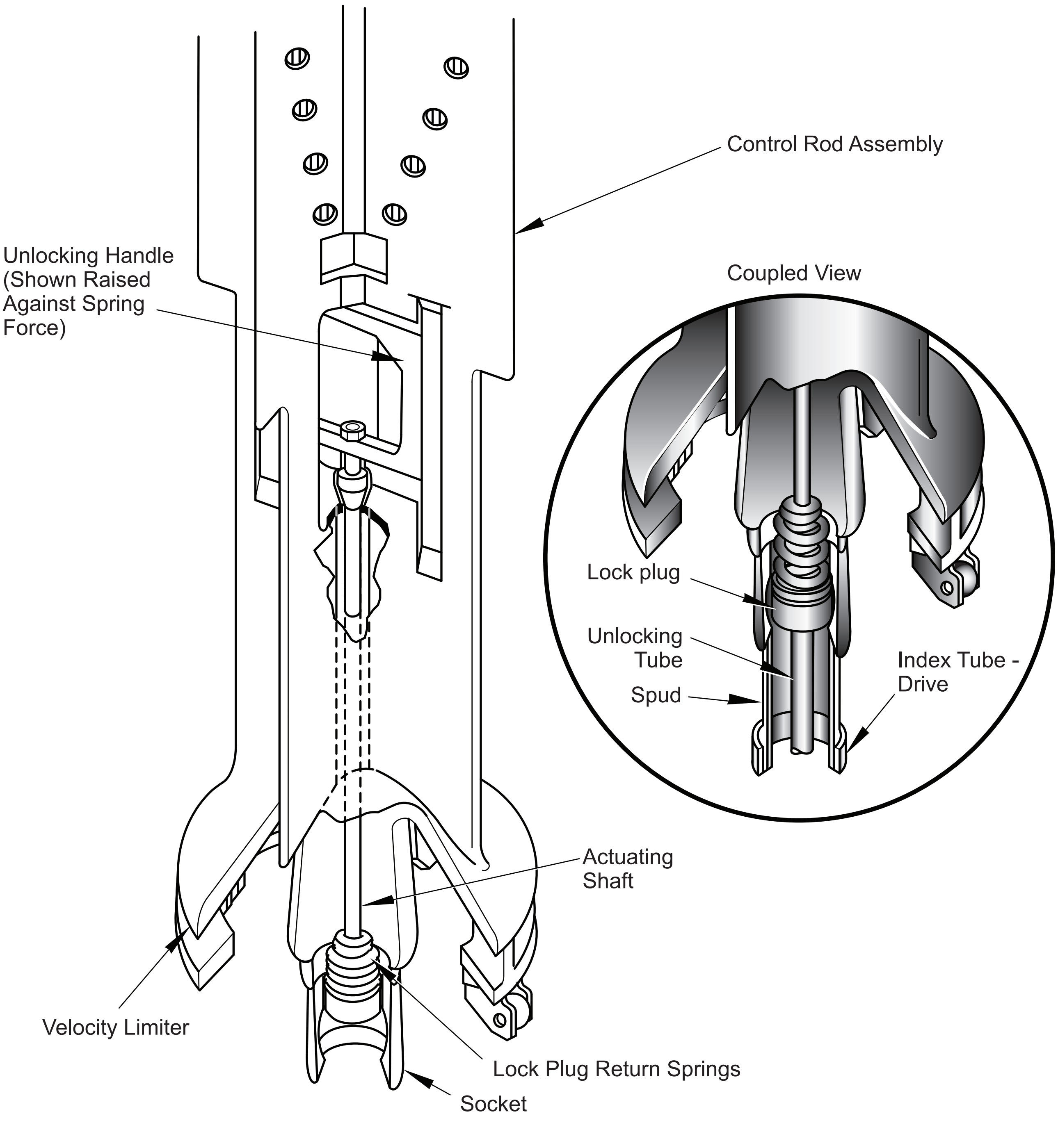
The ARI system constitutes a redundant back-up to the normal scram system and is, therefore, not redundant in itself. That is, the ARI system is only one system with two divisions. Both divisions must function properly for the design basis rod insertion times to be met.

The ARI system is, however, redundant in the aspect of preventing spurious scrams. Each vent point for ARI in the scram air header consists of two valves in series (see Figure 4.6-5). The valves must be energized to vent the air header. This design is intended to prevent spurious scrams and unnecessary cycling of the power plant.

4.6.7 REFERENCES

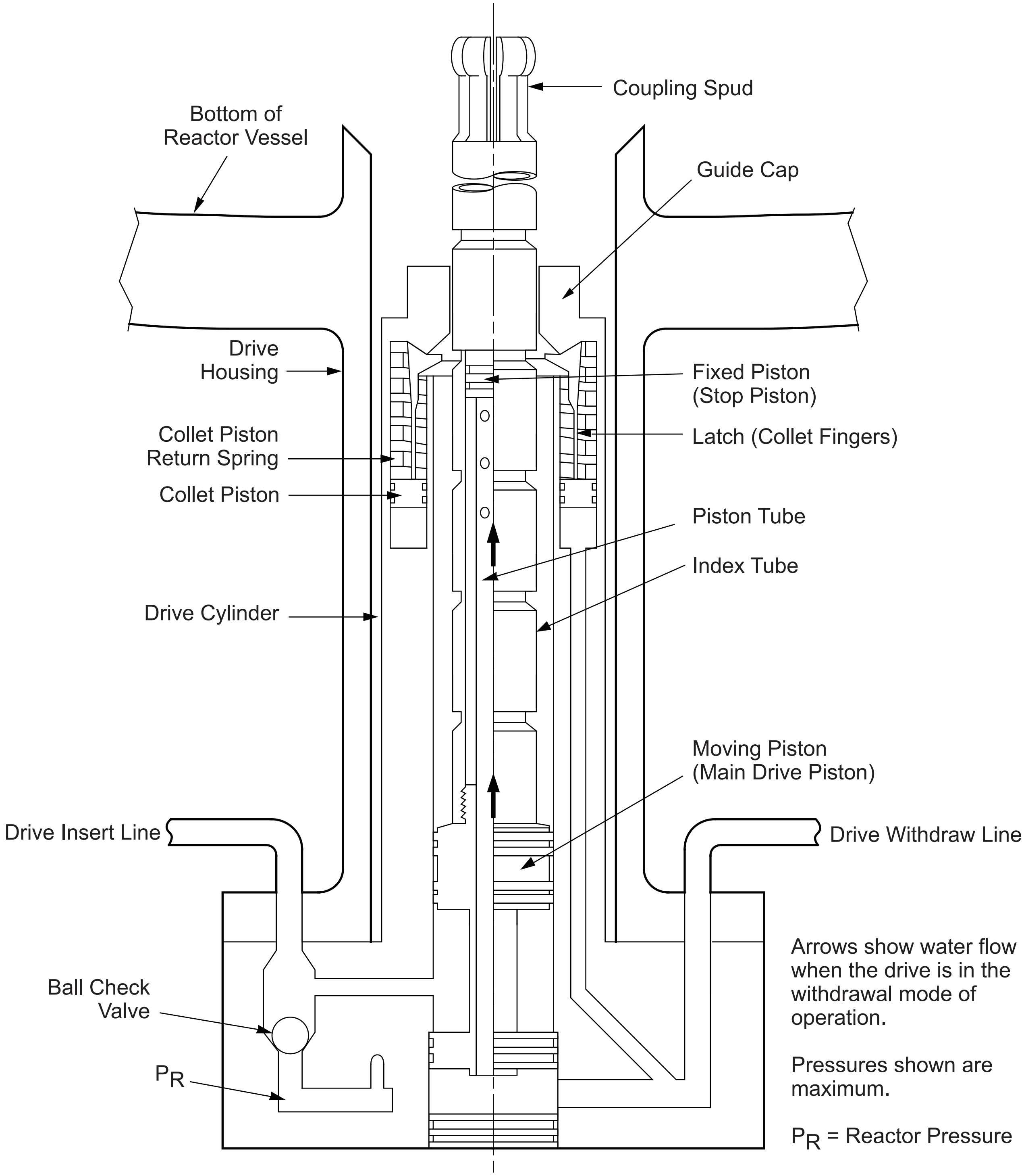
4.6-1 Benecki, J. E., "Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RD B144A," General Electric Company, Atomic Power Equipment Department, APED-5555, November 1967.

4.6-2 NEDE-31096-P, "Licensing Topical Report, Anticipated Transient Without Scram," Response to NRC ATWS Rule 10 CRF 50.62, February 1987.



Control Rod to Control Rod Drive Coupling

Draw. No. 960690.99 | Rev. | Figure 4.6-1



Arrows show water flow when the drive is in the withdrawal mode of operation.

Pressures shown are maximum.

P_R = Reactor Pressure

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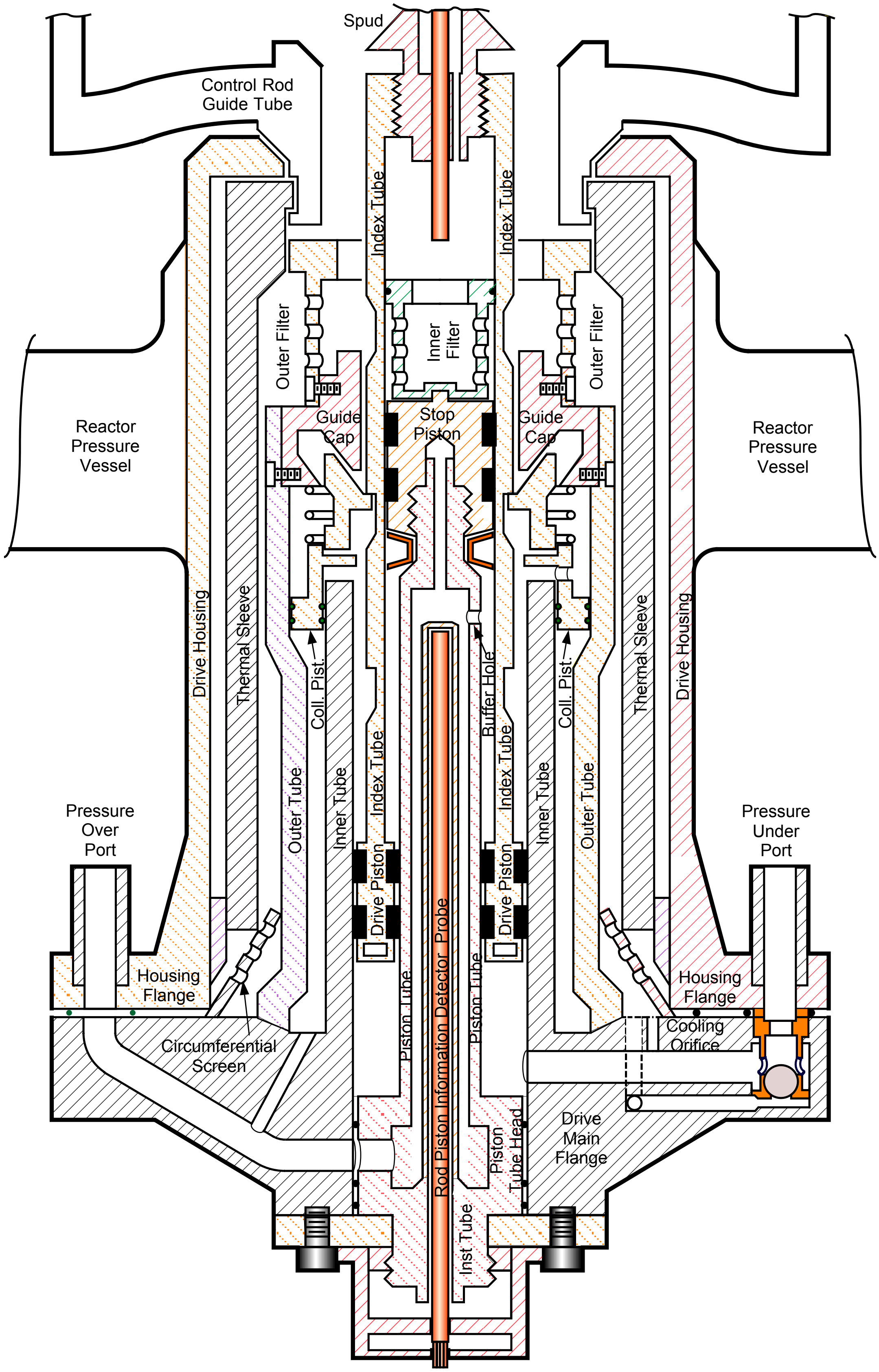
Control Rod Drive Unit

Draw. No. 960222.99 | Rev. | Figure 4.6-2



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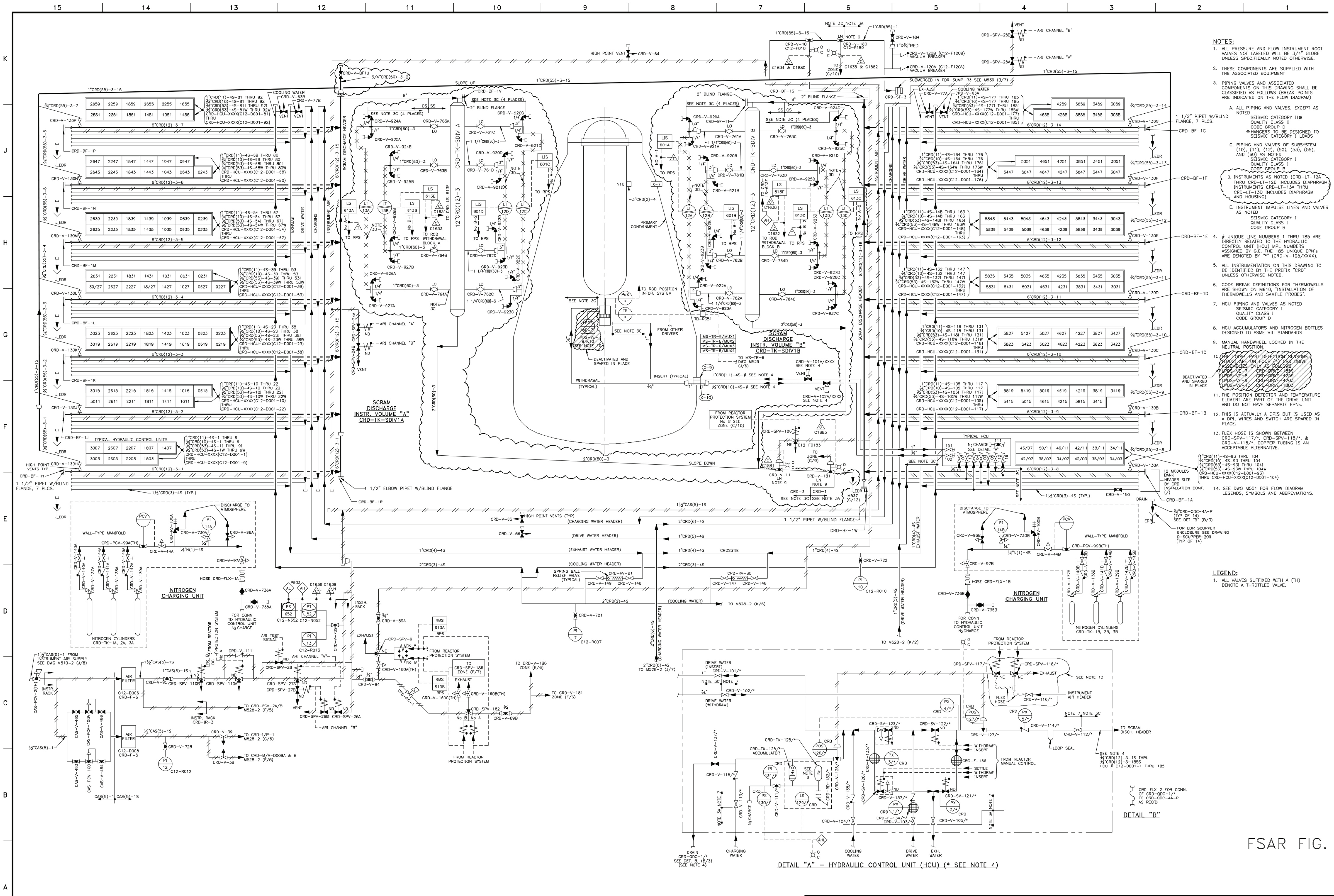
Control Rod Drive Unit (Schematic)

Draw. No. 960222.96	Rev.	Figure 4.6-3



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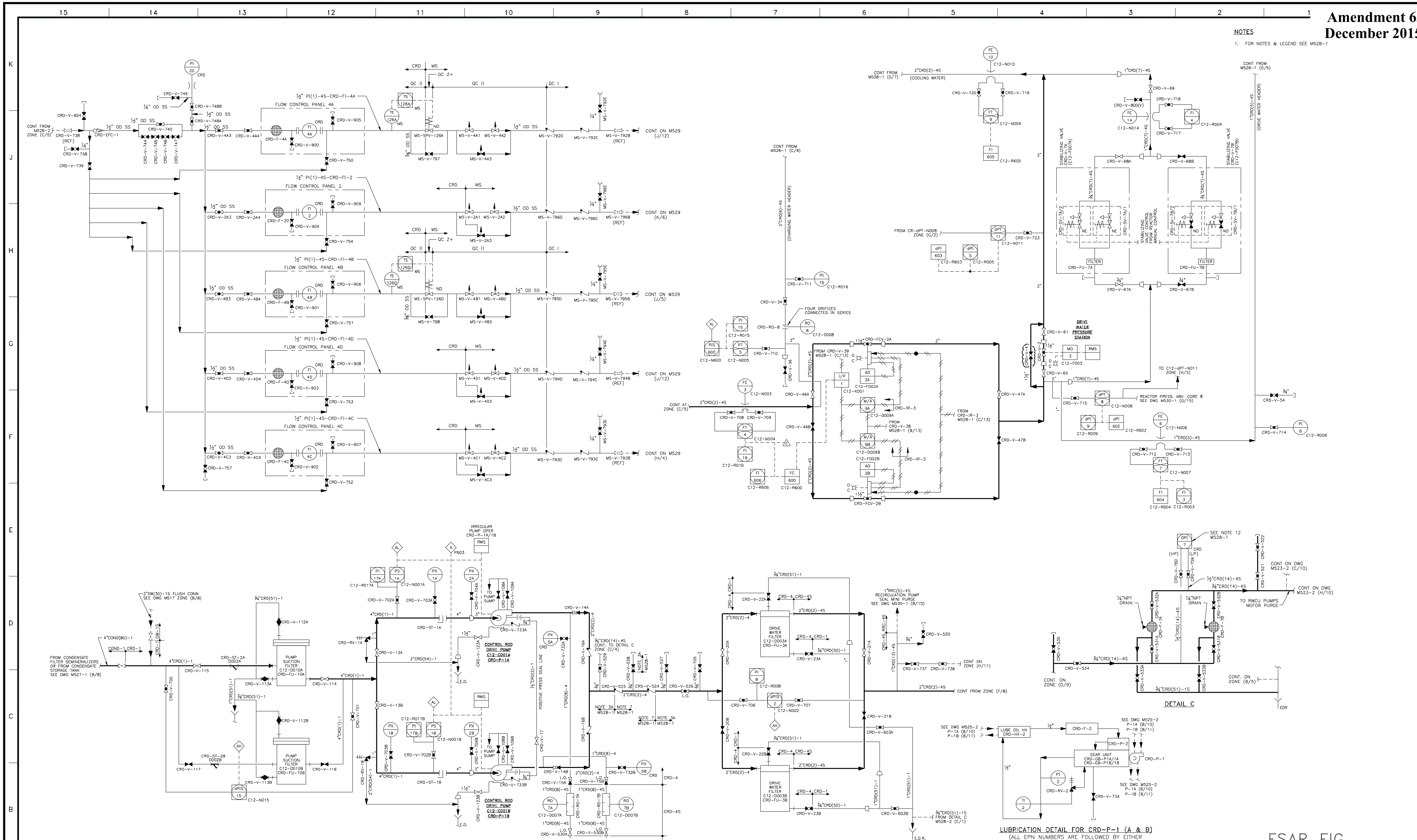
Control Rod Drive Hydraulic System

Draw. No. M528-1	Rev. 80	Figure 4.6-5.1



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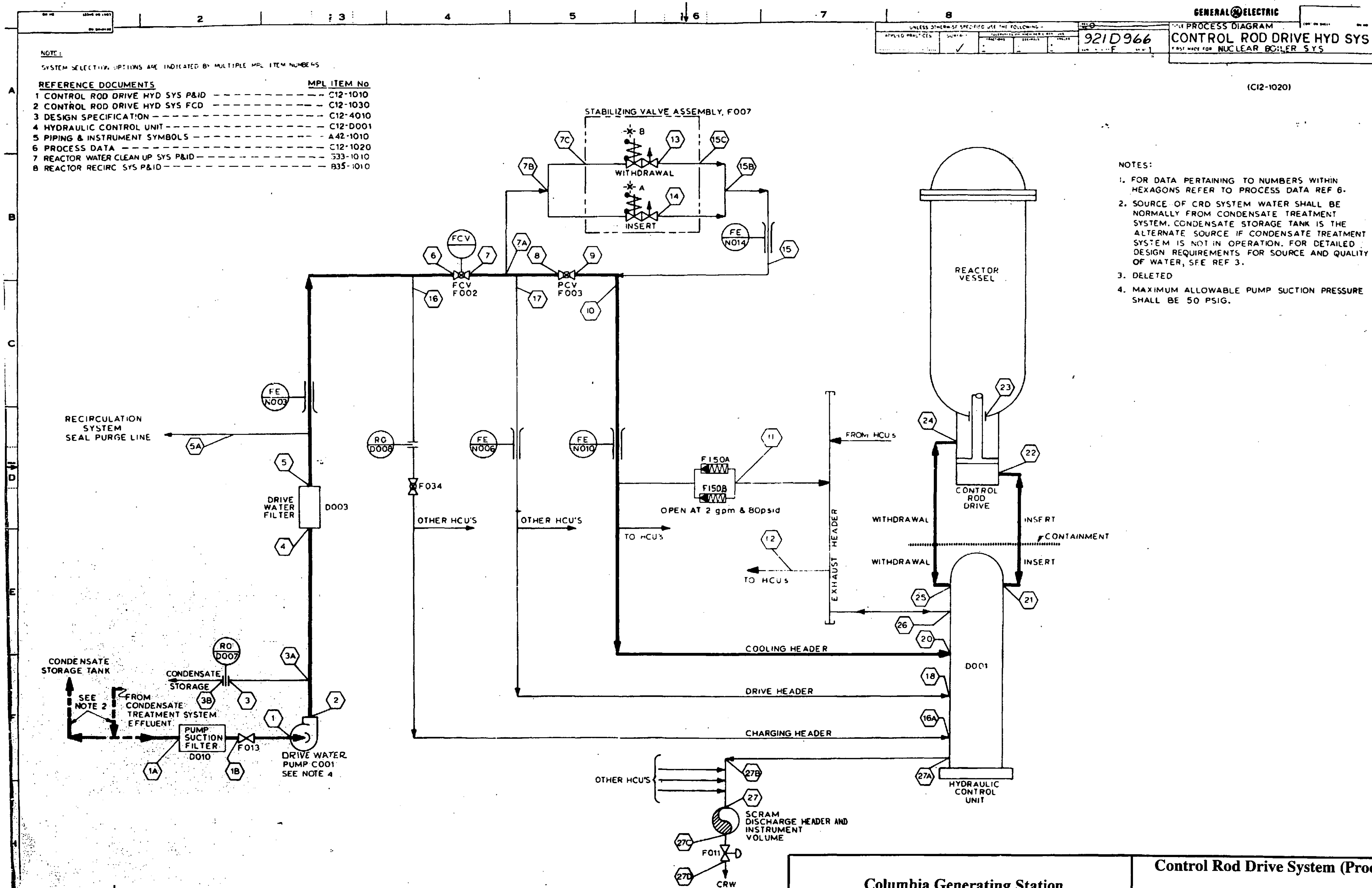
Control Rod Drive Hydraulic System

Draw. No. M528-2	Rev. 9	Figure 4.6-5.2



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Control Rod Drive System (Process Diagram)

Draw. No. 02C12-04,25,1 | Rev. 1 | Figure 4.6-6.1

GENERAL ELECTRIC

PROCESS DIAG DATA
CONTROL ROD DRIVE HYD SYSTEM
921D966AA

MPL NO. C12-1020

MODE A NORMAL OPERATION

LOCATION	1A	1	2	3	4	5	5A	6	7	8	9	10	11	12	13
FLOW, GPM	93	93	93	20	73	73	10	63	63	57	57	63	0	0	2
PRESSURE PSIG	21	19	1487	1487	1476	1462	1462	1455	PR + 260	PR + 260	PR + 30	PR + 30	PR	PR	PR + 30

LOCATION	14	15	16	17	18		20	21	22	23	24	25	26	27	
FLOW, GPM	4	6	0	0	0		.34 MAX	.34 MAX	.34 MAX	.34 MAX	0	0	0	0	
PRESSURE PSIG	PR + 30	PR + 30	1455				PR + 15	PR + 14	PR + 14	PR	PR		PR	0	

CONDITIONS:
1. DRIVES LATCHED
2. PRESSURE OF REACTOR (PR) AT 1000 PSIG.
3. MAXIMUM COOLING FLOW TO DRIVES. MINIMUM REQUIRED PRESSURE AT POSITION 1A IS 20 FEET OF WATER AT 200 GPM.

MODE A SIZES THE COOLING WATER HEADERS.

LINE LOSS FROM LOCATION 10 TO LOCATION 20 SHALL NOT EXCEED 3 PSIG.

MODE B ROD INSERTION

LOCATION	1A	1	2	3	4	5	5A	6	7	8	9	10	11	12	13
FLOW, GPM	93	93	93	20	73	73	10	63	63	57	57	59	0	.7	2
PRESSURE PSIG	21	19	1487	1487	1476	1462	1462	1455	PR + 260	PR + 260	PR + 30	PR + 30	<PR + 8	<PR + 8	PR + 30

LOCATION	14	15	16	17	18		20	21	22	23	24	25	26	27	
FLOW, GPM	0	2	0	4	4		0	4	4	1.3	.7	.7	.7	0	
PRESSURE PSIG	PR + 30	PR + 30	1455	PR + 260	PR + 250		PR + 15	PR + 91	PR + 90	PR	PR + 20 MAX	PR + 20 MAX	PR + 8 MAX	0	

CONDITIONS:
1. DRIVE INSERTING
2. PRESSURE OF REACTOR (PR) AT 1000 PSIG.
3. MAXIMUM DRIVING FLOW TO DRIVES

MODE B SIZES THE DRIVE WATER HEADERS.

MODE C SCRAM

LOCATION	1A	1	2	3	4	5	5A	6	7	8	9	10	11	12	13
FLOW, GPM	45	45	45	20	25	25	10	15	15	15	15	15	15	14.9	0
PRESSURE PSIG	21	21	1550	1550									SEE NOTE 9	SEE NOTE 9	

LOCATION	14	15	16	17	18		20	21	22	23	24	25	26	27	
FLOW, GPM	0	0	0	0	0		0	90	90	-3.6	- 30	30	0.1 + SEE NOTE 9	APPROX 5565	
PRESSURE PSIG								1167 MIN	731 MIN	PR	256 MAX	94		65 MAX SEE NOTE 10	

CONDITIONS:
1. DRIVES SCRAMMING
2. PRESSURE OF REACTOR (PR) AT 1000 PSIG.
3. FLOWS BASED ON MAXIMUM ROD VELOCITY OF 85 INCHES PER SECOND.

MODE C SIZES THE INSERT AND WITHDRAW LINES.

MODE D SCRAM COMPLETED

LOCATION	1A	1	2	3	4	5	5A	6	7	8	9	10	11	12	13
FLOW, GPM	200	200	200	20	180	180	10	15	15	15	15	15	15	14.9	0
PRESSURE PSIG	21	19	1210						>PR	>PR	>PR	>PR	>PR	>PR	

LOCATION	14	15	16	17	18		20	21	22	23	24	25	26	27	
FLOW, GPM	0	0	155	0	0		0	0.92	0.92	0.92	SEE NOTE 9	SEE NOTE 9	0.1	0	
PRESSURE PSIG			988					76	76	PR	65 MAX	65 MAX		65 MAX	

SEE NOTE 10

CONDITIONS:
1. SCRAMMING OF DRIVES COMPLETED
2. PRESSURE OF REACTOR (PR) AT 0 PSIG.
3. MAXIMUM CRD SUPPLY PUMP FLOW.

MODE D SIZES THE PUMP SUCTION LINE.

NOTE: MINIMUM ACCUMULATOR PRECHARGE PRESSURE IS 565 PSIG.

TABLE I

LOCATION	1A–1B	1B--1	2---6	3A–3B	6--9	7A–7B	7B–7C
DESIGN PRESS. (PSIG.)	150	150	1750	1750	1750	1750	1750
DESIGN TEMP. (DEG F)	150	150	150	150	150	150	150
ESTIMATED LINE SIZE (INCHES)	4	4	2	1	1.5	1	0.75

LOCATION	10–20	11–12	15B–15C	15–15B	16–16A	17–18	12–26
DESIGN PRESS. (PSIG.)	1750	1750	1750	1750	1750	1750	1750
DESIGN TEMP. (DEG F)	150	150	150	150	150	150	150
ESTIMATED LINE SIZE (INCHES)	2**	1	0.75	1	2	1	1

LOCATION	21–22 "SEE NOTE 13"	24–25 "SEE NOTE 13"	27A–27B "SEE NOTE 13"	27B–27 "SEE NOTE 13"	27–27C "SEE NOTE 14"	27C–27D "SEE NOTE 14"	5A
DESIGN PRESS. (PSIG.)	1750	1750	1250	1250	1250	1250	1750
DESIGN TEMP. (DEG F)	150	500 (PEAK)	450*** (PEAK)	450*** (PEAK)	450*** (PEAK)	450*** PEAK)	150
ESTIMATED LINE SIZE (INCHES)	1	0.75	0.75	*	10	2	.75

* SEE CRD SYSTEM DESIGN SPECIFICATION.

** 2 INCH HEADER TO EACH HALF OF THE TOTAL QUANTITY OF HCU'S.

*** MOMENTARY TEMPERATURE THAT OCCURS AT 65 PSIG. REFER TO SPEC 1 FOR MAXIMUM DESIGN PRESSURE AND TEMPERATURE.

NOTES:

1. DEFINITION OF SYMBOLS
   PR - INDICATES PRESSURE OF THE REACTOR
2. MAXIMUM OPERATING TEMPERATURES
   THE MAXIMUM SYSTEM OPERATING TEMPERATURE WILL NOT EXCEED 150 DEG. F. FROM LOCATION 1 THROUGH 27 WITH THE FOLLOWING EXCEPTIONS.

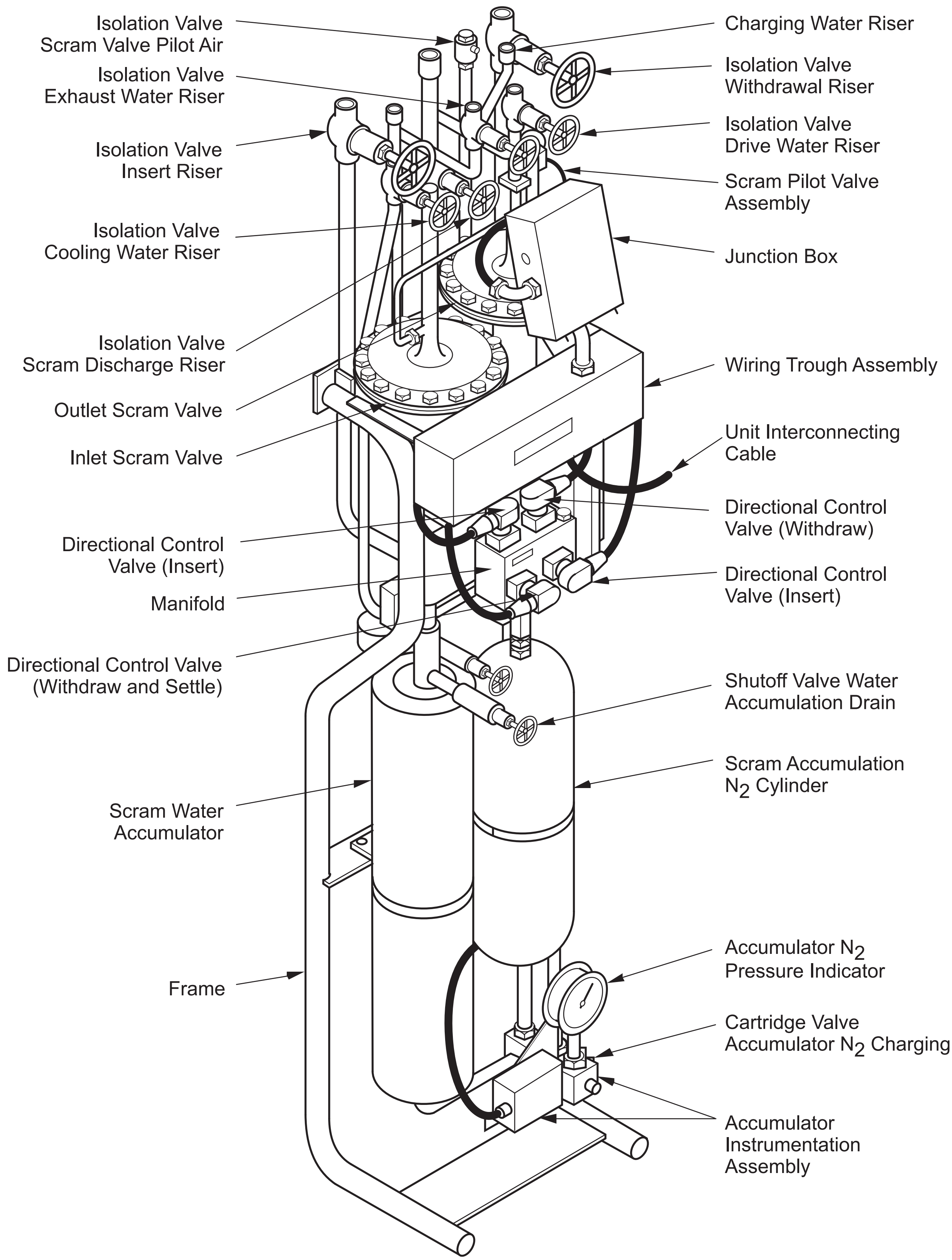
	LOCATION	MAXIMUM TEMP. (DEG. F.)
MODE A -	23	200
MODE A -	23	546
MODE A - (LEAKING SCRAM DISCHARGE VALVE)	24	500
	25	500
	27	280
MODE D -	23	475
	24	475
	25	475
	27	450***

3. MODE A -
   A. MAXIMUM CHARGING WATER PRESSURE SHALL BE 1600 PSIG NOMINAL, ACCUMULATOR PRECHARGE PRESSURE SHALL BE 575 PSIG NOMINAL, 580 PSIG MAXIMUM, AT 70° F.
   B. DELETED
   C. LOCATION 20 - THE CRD COOLING WATER PRESSURE SHALL BE DETERMINED BY THE COOLING WATER FLOW.
   D. LOCATION 23 - MAXIMUM DRIVE COOLING REQUIREMENTS WILL NOT EXCEED 0.34 GPM/DRIVE FOR THE CONDITIONS LISTED. MINIMUM DRIVE COOLING REQUIREMENTS WILL NOT BE LESS THAN 0.20 GPM/DRIVE.
4. MODE B -
   A. LOCATION 13 AND 14 - INSERT VALVE F007-A CLOSES ON DRIVE INSERT SIGNAL. WITHDRAW VALVE F007-B CLOSES ON DRIVE WITHDRAW SIGNAL BUT DOES NOT STAY CLOSED DURING SETTLING.
   B. LOCATION 18 - THE CRD DRIVE WATER PRESSURE SHALL NOT BE LESS THAN PR + 250 PSIG. FOR THE CONDITIONS INDICATED.
5. MODE C -
   A. DELETED
   B. THE TEMPERATURES LISTED IN NOTE 2 FOR POSITION 24, 25 AND 27 MAY BE ASSUMED TO OCCUR LESS THAN 1 PERCENT OF THE OPERATING LIFE OF THE SYSTEM. SEE THE CRD HYDRAULIC SYSTEM DESIGN SPECIFICATION TO DETERMINE CYCLIC STRESS DUE TO THERMAL EXPANSION.
   C. LOCATION 21 TO 22 - THE PRESSURE DROP FROM LOCATION 21 TO 22 SHALL NOT EXCEED 435 PSI AT 90 GPM FOR ANY CRD.
   D. LOCATION 23 - A NEGATIVE FLOW RATE INDICATES FLOW FROM THE REACTOR THROUGH THE DRIVE SEAL, INTO THE CRD. THE MAXIMUM LEAK RATE FROM THE THE REACTOR CAN REACH 10 GPM PER DRIVE.
   E. LOCATION 24 TO 25 - THE PRESSURE DROP FROM LOCATION 24 TO 25 SHALL NOT EXCEED 162 PSI AT 30 GPM FOR ANY CRD.
   F. RESPONSE TIME OF FCV-F002 IS SUCH THAT SCRAM IS COMPLETED BEFORE FCV-F002 STARTS TO CLOSE.
   G. SCRAM DRAIN VALVE F011 AND VENT VALVE F010 CLOSE WITH A SCRAM SIGNAL.
6. MODE D -
   A. DELETED
   B. LOCATION 27 - THE SCRAM DISCHARGE VOLUME SHALL BE SIZED SO THAT THE RESULTING PRESSURE AFTER 100 PERCENT STROKE IS LESS THAN 65 PSIG.
7. MAXIMUM ALLOWABLE PUMP SUCTION PRESSURE SHALL BE 50 PSIG.
8. PROCESS DIAGRAM 921D966 SHALL BE USED WITH AND FORM PART OF THIS PROCESS DATA. IF THERE ARE ANY CONFLICTS BETWEEN THE PROCESS DIAGRAM AND THIS PROCESS DATA, THE PROCESS DATA SHALL GOVERN.
9. DURING SCRAM, THIS FLOW WILL BE DIRECTED INTO THE SCRAM DISCHARGE VOLUME. FOLLOWING SCRAM, THIS FLOW WILL DECLINE AS VALVE F002 CLOSES AND AS THE SCRAM DISCHARGE VOLUME PRESSURIZES TO EQUAL THE REACTOR PRESSURE. AFTER THE SCRAM DISCHARGE VOLUME AND THE REACTOR VESSEL PRESSURE HAVE EQUALIZED, FLOW WILL BE DIVERTED TO THE REACTOR VESSEL VIA THE CRD WITHDRAW LINES AT A FLOW RATE DEPENDENT ON THE REACTOR PRESSURE:
   I.E. (A.) APPROX. 15 GPM AT "0" PSIG. REACTOR PRESSURE.
   (B.) APPROX. 6 GPM AT "1000" PSIG. REACTOR PRESSURE.
10. THIS VALUE APPLIES IMMEDIATELY FOLLOWING COMPLETION OF SCRAM. PRESSURE WILL SUBSEQUENTLY EQUALIZE WITH REACTOR PRESSURE.
11. DESIGN PRESSURE AND TEMPERATURE SHOWN IN "TABLE 1" IS FOR INFORMATION ONLY AND IS THE BASIS FOR DESIGN OF BWRS SUPPLIED EQUIPMENT. ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL LINE SIZES AS DETERMINED BY THE PIPING DESIGNER SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENTS.
12. ALL VALUES SHOWN IN MODES A, B, C, AND D ARE NOMINAL UNLESS-OTHERWISE NOTED.
13. INSERT AND WITHDRAWAL PIPING SHALL BE DESIGNED FOR HYDRODYNAMIC LOADS AS A RESULT OF A NORMAL SCRAM AT ZERO & NORMAL REACTOR PRESSURES SHORT STROKE AND FULL STROKE SCRAM AND A SCRAM WITH FAILED CRD BUFFER. PLANT LOAD COMBINATIONS SHOULD INCLUDE CONSIDERATION OF THOSE SYSTEM HYDRODYNAMIC LOADS.
14. THE SCRAM DISCHARGE VOLUME (SDV) AND ITS VENT AND DRAIN PIPING DESIGN SHALL CONSIDER THE HYDRODYNAMIC LOADS WHICH MAY OCCUR DUE TO 1) SDV ISOLATION AND 2) SDV VENTING AND DRAINING FOLLOWING A SCRAM COMPLETION AT REACTOR OPERATING PRESSURE.

FSAR FIG.

Columbia Generating Station Final Safety Analysis Report	Control Rod Drive System (Process Diagram)		
	Draw. No. 02C12-04,26,2	Rev. 3	Figure 4.6-6.3

Amendment 53
November 1998



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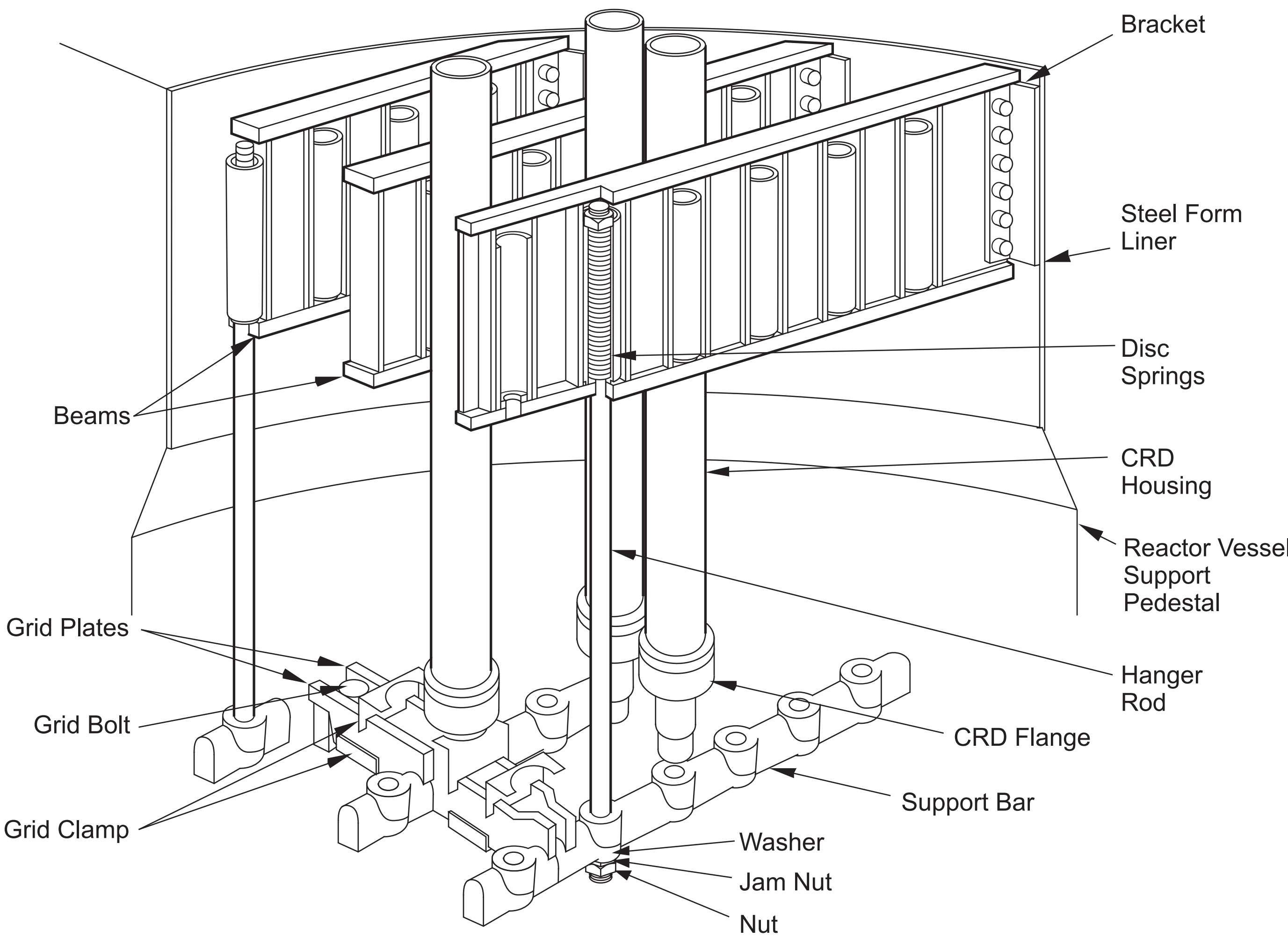
Control Rod Drive Hydraulic Control Unit

Draw. No. 900547.25	Rev.	Figure 4.6-7

Form No. 960690



Control Rod Drive Housing Support

Draw. No. 900547.26 | Rev. | Figure 4.6-8

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REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

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Chapter 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

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

The RCPB includes all pressure-containing components such as pressure vessels, piping, pumps, and valves, which are

a. Part of the reactor coolant system, or

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

    1. The outermost containment isolation valve in system piping that penetrates primary reactor containment,

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

    3. The reactor coolant system safety/relief valves.

Section 5.4 discusses the various subsystems to the RCPB.

The nuclear system pressure relief system protects the reactor coolant pressure boundary from damage due to overpressure. To protect against overpressure, pressure-operated relief valves are provided that can discharge steam from the nuclear system to the suppression pool. The pressure relief system also acts to automatically depressurize the nuclear system in the event of a loss-of-coolant accident (LOCA) in which the high-pressure core spray (HPCS) system fails to maintain reactor vessel water level. Depressurization of the nuclear system allows the low-pressure core cooling systems to supply enough cooling water to adequately cool the fuel. Section 5.2.5 establishes the limits on nuclear system leakage inside the drywell so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

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

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

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

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

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

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available (e.g., hot standby). One mode of RHR operation allows the removal of heat from the primary containment following a LOCA. Another operational mode of the RHR system is

low-pressure coolant injection (LPCI). The LPCI operation is an engineered safety feature for use during a postulated LOCA. This operation is described in Section 6.3. The low-pressure core spray (LPCS) system also provides protection to the nuclear system.

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

5.1.1 SCHEMATIC FLOW DIAGRAM

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

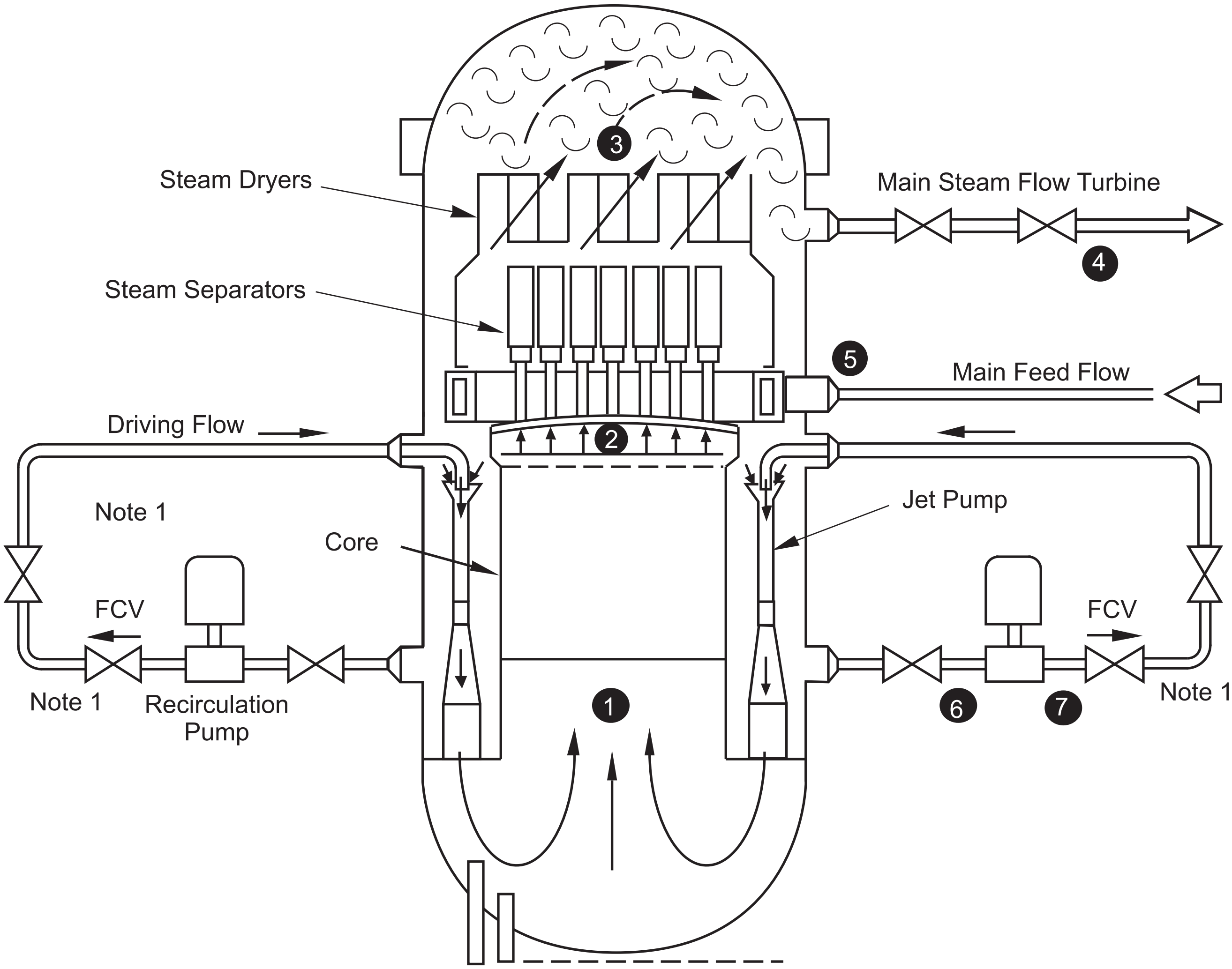
5.1.2 PIPING AND INSTRUMENTATION DIAGRAM

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

a. The nuclear boiler, main steam, and feedwater systems shown in Figure 10.3-2,
b. Recirculation system shown in Figure 5.4-7,
c. RCIC system shown in Figure 5.4-11,
d. RHR system shown in Figures 5.4-16 and 5.4-17,
e. Reactor water cleanup system shown in Figure 5.4-22,
f. HPCS system shown in Figure 6.3-4,
g. LPCS system shown in Figure 6.3-4, and
h. Standby liquid control system shown in Figure 9.3-14.

5.1.3 ELEVATION DRAWING

An elevation drawing showing the principal dimensions of the reactor and coolant system in relation to the containment is shown in Figures 1.2-11 and 1.2-12.



	PRESSURE (psia)	FLOW (lb/hr)	TEMP. (°F)	ENTHALPY (Btu/lb)
1. Core Inlet	1069 #	108.5 x 10^6*	534 #	528.5
2. Core Outlet	1047 #	108.5 x 10^6	550 #	639.9 #
3. Separator Outlet (Steam Dome)	1035	15.28 x 10^6	549 #	1191.0
4. Steam Line (2nd Isolation Valve)	999	15.28 x 10^6	545 #	1191.0
5. Feedwater Inlet (Includes RWCU Return Flow)	1063 #	15.4 x 10^6	422	399.7
6. Recirculating Pump Suction	1037 #	32 x 10^6 #	534 #	528.4 #
7. Recirculating Pump Discharge	1327 #	32 x 10^6 #	534.4	529.5

* Channel Bypass - Nominally 10%
Note 1: The FCVs are kept in mechanically blocked full open position.
Note 2: These values identified by # are based upon 3486 MWt and were dispositioned as having insignificant change from or effect to the operating conditions for 3544 MWt.

Columbia Generating Station
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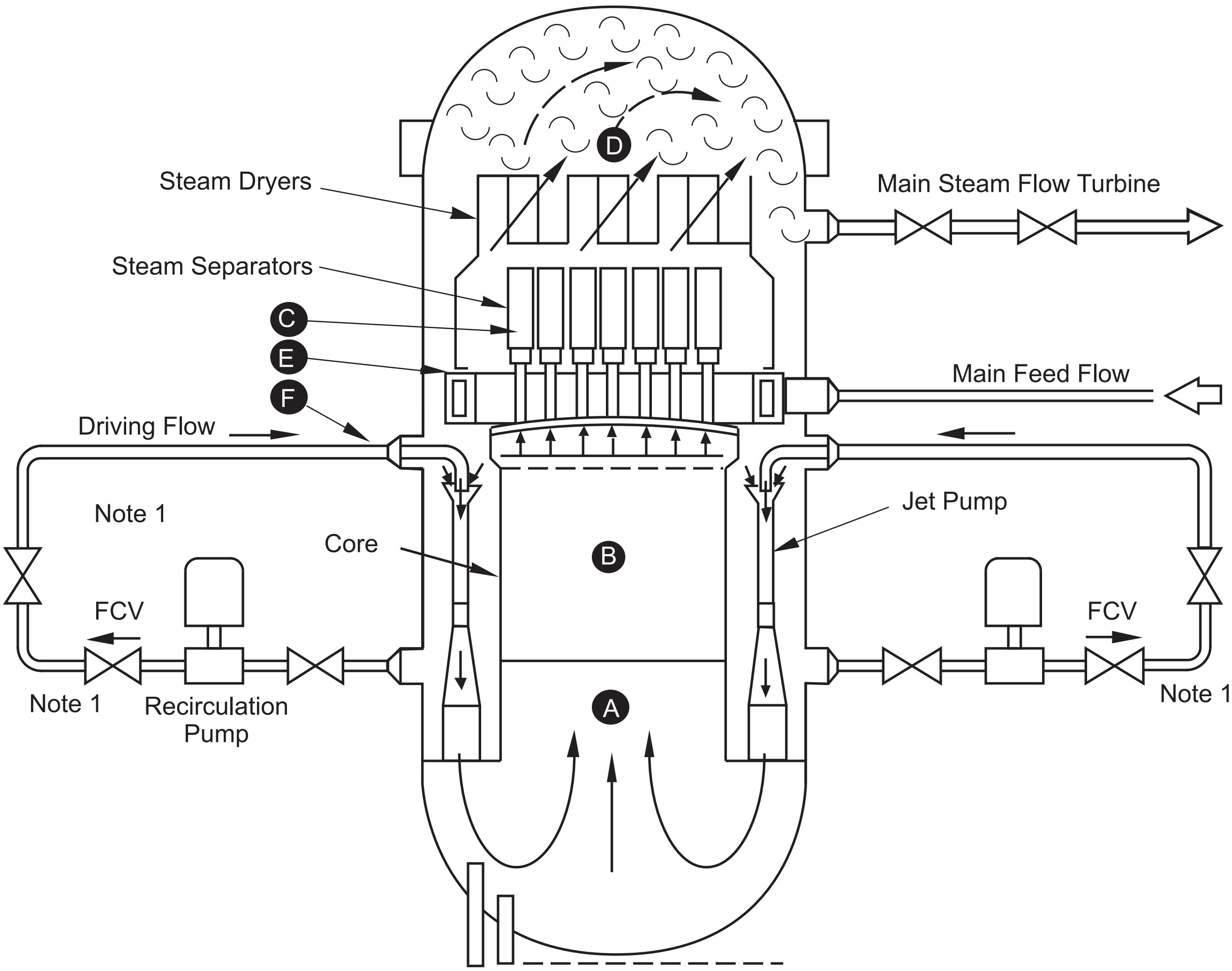
Rated Operating Conditions of the Boiling Water Reactor

Draw. No. 900547.44 | Rev. | Figure 5.1-1



	Volume of Fluid (ft^3)
A. Lower Plenum	4010
B. Core	1990
C. Upper Plenum and Separators	2290
D. Dome (Above Normal Water Level)	7160
E. Downcomer Region	5210
F. Recirculating Loops and Jet Pumps	1010

Note1: The FCVs are kept in mechanically blocked full open position.

Columbia Generating Station Final Safety Analysis Report	**Coolant Volumes of the Boiling Water Reactor**		
	Draw. No. **960690.04**	Rev.	Figure **5.1-2**

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

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

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10 CFR Part 50, Section 50.55a

Table 3.2-1 shows compliance with the rules of 10 CFR Part 50.55a "Codes and Standards." The American Society of Mechanical Engineers (ASME) Code edition, applicable addenda, and component dates are in accordance with 10 CFR 50.55a except for those RCPB components listed in Table 5.2-1. The design, fabrication, and testing of the RCPB components listed in Table 5.2-1 were in accordance with the recognized codes and standards in effect at the time the components were ordered as shown in the table. The code edition and applicable addenda that would be required by strict interpretation of the rules set forth in 10 CFR 50.55a are identified in Table 5.2-1.

Application for Columbia Generating Station (CGS) was filed with the Commission in August 1971. At that time a construction permit was expected before the end of the 1972, but requests for additional seismic data in August 1972 caused the issuance of the construction permit to go beyond the end of the year to March 19, 1973. As is common practice in the utility industry, Energy Northwest proceeded with the engineering, design, and material and components procurement in anticipation of the award of a construction permit to meet construction schedules. Had the construction permit been issued as initially expected, the requirements of 10 CFR 50.55a would have been met to the letter of the law.

However, in each instance of exception the ASME Code version applied was one addenda earlier (6 months) than the code version required by the rules of 10 CFR 50.55a. The changes embodied in the later ASME Code addenda were reviewed. It was concluded that the addenda required by the rules of 10 CFR 50.55a affected documentation format but imposed no new technical requirements or changes in quality control procedures from the code version applied in the procurement of the components. The level of safety and quality provided by conformance to the earlier code edition and addenda applied in procurement is equivalent to that which would be required by strict application of the rules of 10 CFR 50.55a. The effort and expense of recertification of these components, which had all been shipped to the construction site, would not have provided a compensating increase in the level of safety and quality.

5.2.1.2 Applicable Code Cases

The reactor pressure vessel (RPV) and appurtenances and the RCPB piping, pumps and valves, were designed, fabricated, and tested in accordance with the applicable edition of the ASME

Code, Section III, including the addenda that were mandatory at the order date for the applicable components. This is in compliance with the intent of Regulatory Guides 1.84 and 1.85. Section 50.55a of 10 CFR Part 50 requires code case approval only for Class 1 components. These code cases contain requirements or special rules which may be used for the construction of pressure-retaining components of Quality Group Classification A. The various ASME Code case interpretations that were applied to components in the RCPB are listed in Table 5.2-2. Code cases listed in Table 5.2-2 are those used in the original construction of CGS. Other code cases that are adopted for use, as approved by Regulatory Guides 1.147, 1.84, 1.85, or specifically approved by the Regulatory Authority for use at CGS, are specified in the component's design specification as required by ASME Section III.

5.2.2 OVERPRESSURIZATION PROTECTION

5.2.2.1 Design Bases

Overpressurization protection is provided in conformance with 10 CFR 50, Appendix A, General Design Criterion 15.

5.2.2.1.1 Safety Design Basis

The nuclear pressure-relief system is designed to

a. Prevent overpressurization of the nuclear system that could lead to the failure of the RCPB,

b. Provide automatic depressurization for small breaks in the nuclear system occurring with maloperation of the high-pressure core spray (HPCS) system so that the low-pressure coolant injection (LPCI) and the low-pressure core spray (LPCS) systems can operate to protect the fuel barrier (see Section 6.3.2.2.2),

c. Permit verification of its operability, and

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

5.2.2.1.2 Power Generation Design Bases

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

a. Discharge to the containment suppression pool, and

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

5.2.2.1.3 Discussion

The ASME Boiler and Pressure Vessel Code (B&PV Code) requires that each component designed to meet Section III be protected from overpressure under upset conditions. The code allows a peak allowable pressure of 110% of design pressure under upset conditions. The code specifications for safety valves require that (a) the lowest safety valve setpoint will be set at or below design pressure, and (b) the highest safety valve setpoint will be set so that total accumulated pressure does not exceed 110% of the design pressure for upset conditions. The SRVs are designed to open by means of either of two modes of operation as discussed in Chapter 15. The safety (spring) setpoints are listed in Table 5.2-3 and satisfy the first of the above-mentioned ASME Code specifications for safety valves because all valves open at less than the nuclear system design pressure of 1250 psig.

The automatic depressurization capability of the nuclear system pressure relief system is evaluated in Sections 6.3 and 7.3.

The following detailed criteria are used in selection of SRVs:

a. Must meet requirements of ASME Code, Section III,

b. Valves must qualify for 100% of nameplate capacity credit for overpressure protection function, and

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

The SRV discharge piping is constructed in accordance with the ASME Code, Section III, 1971 Edition through the Winter 1973 Addenda.

5.2.2.1.4 Safety Valve Capacity

The safety valve capacity of this plant is adequate to limit the primary system pressure, including transients, to the requirements of the ASME B&PV Code, Section III, 1971 Edition through the Summer 1971 Addenda.

Table 5.2-4 lists the systems which could initiate during the safety valve capacity overpressure event.

5.2.2.2 Design Evaluation

5.2.2.2.1 Method of Analysis

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

A detailed description of the models is documented in licensing topical reports, References 5.2-1 and 5.2-7. Safety/relief valves are simulated in the nonlinear representation, and the models thereby allow full investigation of the various valve response times, valve capacities, and actuation setpoints that are available in applicable hardware systems.

The typical capacity characteristic as modeled is represented in Figure 5.2-1 for the spring mode of operation. The associated turbine bypass, turbine control valve (TCV), and main steam isolation valve (MSIV) characteristics are also simulated in the models.

The associated bypass, TCV, main steam isolation characteristics, and anticipated transients without scram (ATWS) pump trip are also represented fully in the models.

5.2.2.2.2 System Design

The overpressure protection system must accommodate the most severe pressurization transient. There are two major transients, the closure of all MSIVs and a turbine generator trip with a coincident failure of the turbine steam bypass system valves, that represent the most severe abnormal operational transients resulting in a nuclear system pressure rise. The evaluation of transient behavior with final plant configuration has shown that the isolation valve closure is slightly more severe when credit is taken only for indirect derived scrams; therefore, it is used as the overpressure protection basis event and shown in Figure 5.2-2. Table 5.2-5 lists the sequence of events of the various systems assumed to operate during the main steam line isolation closure with flux scram event.

Compliance to ASME Code overpressure protection requirements for introduction of GNF2 fuel has been conservatively demonstrated for the limiting overpressure event. The GE thermal-hydraulic and nuclear coupled transient code TRACG (References 5.2-7 and 5.2-8) was used to obtain system response and peak vessel pressure. The setpoints are listed in Table 5.2-3. The evaluation, based on reactor operation at 100% of uprated power, end-of-cycle nuclear dynamic parameters, an initial dome pressure of 1035 psia (nominal uprated dome

pressure), six SRVs with lowest safety setpoints out of service, and SRV opening pressures at 3% above nominal setpoint values resulted in a maximum reactor pressure of 1311 psig.

The scram reactivity curve is shown in Figure 5.2-2.

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 Safety Valve Capacity. The required SRV capacity is determined by analyzing the pressure rise from an MSIV closure with flux scram transient. The plant is assumed to be operating at the turbine-generator design conditions at a nominal vessel dome pressure of 1035 psia. The analysis hypothetically assumes the failure of the direct MSIV position scram. The reactor is shut down by the backup, high neutron flux scram. For the analysis, the spring-action safety valve setpoints used are in the range of 1236 to 1256 psia. The TRACG analysis indicates that the design valve capacity is capable of maintaining adequate margin below the peak ASME Code allowable pressure in the nuclear system (1375 psig). Figure 5.2-2 shows the result of the TRACG analysis. The sequence of events in Table 5.2-5, assumed in these analyses, were investigated to meet code requirements and to evaluate the pressure relief system exclusively.

Under Section III of the ASME B&PV Code, credit can be allowed for a scram from the reactor protection system. In addition, credit is also taken for the protection circuits which are indirectly derived when determining the required SRV capacity.

The backup reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure relieving dual purpose SRVs. Application of the direct position scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required SRV capacity of nuclear vessels under the provisions of the ASME Code. The SRVs are operated in a relief mode (pneumatically) at setpoints lower than those specified under the safety function. This ensures sufficient margin between anticipated relief mode closing pressures and valve spring forces for proper seating of the valves.

The typical parametric relationship between peak vessel (bottom) pressure and SRV capacity for the MSIV transient with high flux scram is described in Figure 5.2-3. Also shown in Figure 5.2-3 is the peak vessel (bottom) pressure for position scram with 18-valve capacity. Pressures shown for flux scram will result only with multiple failure in the redundant direct scram system.

The typical time response of the vessel pressure to the MSIV transient with flux scram is illustrated in Figure 5.2-4. This shows that the pressure at the vessel bottom exceeds 1250 psig for less than 7 sec and does not reach the limit of 1375 psig.

5.2.2.2.3.2 Pressure Drop in Inlet and Discharge. Pressure drop in the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures.

Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent back-pressure on each SRV from exceeding 40% of the valve inlet pressure, thus ensuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each SRV has its own separate discharge line.

5.2.2.2.3.3 Reload Specific Confirmatory Analysis. The calculated vessel pressure for MSIV inadvertent closure may be dependent upon the fuel design and core loading pattern. Compliance with the ASME upset limit is demonstrated by cycle-dependent analysis just prior to the operation of that cycle. The results are reported in Supplemental Reload Licensing Report (Reference 5.2-11).

5.2.2.3 Piping and Instrumentation Diagrams

See Figure 5.2-5 which shows the schematic location and number of pressure-relieving devices. The schematic arrangement of the SRVs is shown in Figures 5.2-6 and 5.2-7.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

The nuclear pressure relief system consists of SRVs located on the main steam lines between the reactor vessel and the first isolation valve within the drywell.

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

A schematic of the main SRV is shown in Figure 5.2-8. It is opened by either of two modes of operation:

a. The spring mode of operation which consists of direct action of the steam pressure against a spring-loaded disk that will pop open when the valve inlet

pressure force exceeds the spring force. Figure 5.2-9 depicts typical valve lift versus opening time characteristics; and

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

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

For overpressure SRV operation (self-actuated or spring lift mode), the spring load establishes the safety valve opening setpoint pressure and is set to open at setpoints designated in Table 5.2-3. In accordance with the ASME Code, full lift in this mode of operation is attained at a pressure not greater than 3% above the setpoint.

To prevent backpressure from affecting the spring lift setpoint, each valve is provided with a bellows and balancing piston to counteract the effects of any static backpressure which may be present in the discharge line before the valve is opened to discharge steam. The bellows isolates steam in the valve discharge chamber from the valve's internals. If the bellows fails, the balancing piston serves as a functional backup by presenting an effective piston area to the back pressure equal to the valve seat area, thus balancing it so there is essentially no net back pressure effect on the setpoint (Figure 5.2-8).

The safety function of the SRV is a backup to the relief function described below. The spring-loaded valves are designed and constructed in accordance with ASME III, 1971 Edition, Paragraph NB-7640, as safety valves with auxiliary actuating devices.

Each SRV is provided with its own pneumatic accumulator and inlet check valve to provide high assurance the valve will actuate in the power-actuated (relief) mode when its pneumatic solenoid valve is energized. The pneumatic accumulator has sufficient capacity to provide one SRV actuation at approximately 1000 psig valve inlet pressure. Although no credit is taken under ASME Code Section III for overpressure protection by the SRVs in their power-actuated mode, power actuation of the SRV will limit peak reactor pressure in the majority of overpressure transients.

Safety/relief valve actuation in the relief mode is initiated by pressure switches (one per valve) which sense reactor steam space pressure at lower values than the spring mode inlet steam opening pressure. The pressure switches initiate the opening of the SRVs by energizing the pneumatic solenoids (one per valve) at the relief setpoints designated in Table 5.2-3.

When the solenoid is actuated, the delay time, maximum elapsed time between receiving the overpressure signal at the valve actuator and the actual start of valve motion, will not exceed

0.1 sec. The maximum full stroke opening time will not exceed 0.15 sec with 1000 psig steam at the valve inlet.

The SRVs can be operated in the power-actuated mode by remote-manual controls from the main control room.

The SRVs are designed to operate to the extent required for overpressure protection in the following accident environments:

a. 340°F for a 3-hr period, at drywell design pressure,
b. 320°F for an additional 3-hr period, at drywell design pressure,
c. 250°F for an additional 18-hr period, at 25 psig drywell pressure, and
d. 200°F during the next 99 days at 20 psig drywell pressure.

The automatic depressurization system (ADS) utilizes selected SRVs for depressurization of the reactor (see Section 6.3). Each of the SRVs utilized for automatic depressurization is equipped with an air accumulator and check valve arrangement. These accumulators ensure that the valves can be held open following failure of the air supply to the accumulators. The designed pneumatic supply to the ADS accumulator is such that, following a failure of the safety-related pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure. For a discussion of the noninterruptible air supply to the ADS valves, see Section 9.3.1. Three ADS SRVs and their associated solenoid pilot valves (SPV) are qualified for the full post-LOCA time frame for long-term cooling. All other SRVs and their SPVs are qualified for 24 hr post-LOCA to provide overpressure protection capability.

The valve position indication (VPI) and the tailpipe temperature indication systems are discussed in Section 7.5.2.

Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Safety/relief valve discharge line piping from the SRV to the suppression pool consists of two parts. The first part is attached at one end to the SRV and at its other end penetrates and is welded to a 28-in. downcomer (considered a pipe anchor). The main steam piping, including this portion of the SRV discharge piping, is analyzed as a complete system. This portion of the SRV discharge line is classified as Quality Group C and Seismic Category I down to the jet deflector plate just above the diaphragm floor (through which it is rigidly guided) and Quality Group B and Seismic Category I from the jet deflector plate to the downcomer.

The second part of the SRV discharge piping extends from the downcomer (anchor) to the suppression pool. Because of the anchor on this part of the line, it is physically decoupled from the main steam header and is, therefore, analyzed as a separate piping system. In analyzing this part of the discharge piping in accordance with the requirements of Quality Group B, the following load combination was considered as a minimum:

a. Pressure and temperature,
b. Dead weight, and
c. Fluid dynamic loads due to SRV operation.

As a part of the preoperational and startup testing of the main steam lines, movement of the SRV discharge lines were inspected with negligible vibration observed.

The SRV discharge piping is designed to limit valve outlet pressure to 40% of maximum valve inlet pressure with the valve open. Water in the line more than a few feet above suppression pool water level would cause excessive pressure at the valve discharge when the valve is again opened. For this reason, redundant 10-in. vacuum relief valves are provided on each SRV discharge line to prevent drawing an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. Each vacuum relief valve pair is situated with the valves in parallel, the discharge being routed to a common tee in the SRV discharge line.

The nuclear pressure relief system automatically depressurizes the nuclear system sufficiently to permit the LPCI and LPCS systems to operate as a backup for the HPCS system. Further descriptions of the operation of the automatic depressurization feature are found in Sections 6.3 and 7.3.1.1.1.

5.2.2.4.2 Design Parameters

Table 5.2-6 lists design temperature, pressure, and maximum test pressure for the RCPB components. The specified operating transients for components within the RCPB are given in Section 3.9. Refer to Section 3.7 for discussion of the input criteria for design of Seismic Category I structures, systems, and components.

A summary of the number of cycles for transients used in design and fatigue analysis is listed in Table 3.9-1 and categorized under the appropriate design condition (i.e., normal, upset, emergency, and faulted).

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

5.2.2.4.2.1 Safety/Relief Valve. The discharge area of the valve is 16.117 in.^{2} and the coefficient of discharge KD is equal to 0.966, as certified by the National Board of Boiler and Pressure Vessel Inspectors.

The design pressure and temperature of the valve inlet and outlet are 1250 psig at 575°F and 625 psig at 500°F, respectively.

The valves have been designed to achieve the maximum practical number of actuations consistent with state-of-the-art technology. Cyclic testing has demonstrated that the valves are capable of at least 60 actuation cycles between required maintenance.

See Figure 5.2-8 for a schematic cross section of the valve.

5.2.2.5 Mounting of Pressure Relief Devices

The pressure relief devices are located on the main steam piping headers. The mounting consists of a special contour nozzle and an oversized flange connection. This provides a high integrity connection that accounts for the thrust, bending, and torsional loadings which the main steam pipe and relief valve discharge pipe are subjected to.

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

5.2.2.6 Applicable Codes and Classification

The RCPB overpressure protection system is designed to satisfy the requirements of Section III, Subsection NB, of the ASME B&PV Code. The general requirements for protection against overpressure as given NB-7120 of Section III of the code recognize that RCPB overpressure protection is one function of the reactor protective systems and allows the integration of pressure relief devices with the protective systems of the nuclear reactor. Hence, credit is taken for the scram protective system as a complementary pressure protection device.

5.2.2.7 Material Specification

Pressure retaining components of SRVs are constructed only from ASME Section III, Class 1 designated materials.

5.2.2.8 Process Instrumentation

Overpressure protection process instrumentation is listed in Table 1 of Figure 5.2-5 and shown in Figure 10.3-2.

5.2.2.9 System Reliability

Overpressure protection system reliability is principally a function of the SRVs in their spring-opening mode of operation. No credit is taken in the ASME Code Section III required overpressure protection report for power actuation of the SRVs to provide protection against overpressure.

Section 5.2.2.10 discusses the inspection and testing conducted to ensure high SRV reliability. As demonstrated by the extensive qualification and production testing, the valves are very reliable.

In addition to SRV testing to ensure high SRV quality, an extensive in-depth quality assurance program was followed in the manufacture and production testing of the valves to provide assurance of high quality.

A significant amount of BWR operating experience was been accumulated on this type of SRV, approximately 150 individual valve years, only one "stuck-open relief valve" had occurred. This was due to an air solenoid valve sticking open after it was deenergized, thus holding the SRV open in the power-actuated mode. Proper maintenance procedures are incorporated into the instruction manual to preclude recurrence.

This type of SRV has demonstrated good inservice operability similar to that demonstrated by the qualification test program.

In summary, this type of SRV has demonstrated excellent reliability, both in qualification testing and in actual BWR operation.

5.2.2.10 Inspection and Testing

To verify the design of the SRV used will reliably operate, several SRVs were subjected to qualification test programs. These qualification test programs demonstrated the design of the valve is capable of performing its overpressure protection function under normal, upset, emergency, and faulted conditions and its designated mechanical motion(s) to fulfill its safety function to shut down the plant or mitigate the consequence of a postulated event. To ensure that valves to be installed are operable, each valve is manufactured, inspected, and production tested in accordance with quality control procedures to verify compliance with both ASME Code and operability assurance acceptance criteria.

The SRV design used at CGS successfully completed the following qualification tests:

a. Life Cycle Test

   Following the prequalification production tests, each modified SRV was then subjected to life cycle qualification tests with saturated steam conditions, in accordance with GE specification 22A6595. This included approximately 300 relief (power) and safety (pressure) actuations to demonstrate and characterize each valve for acceptable BWR service. Tests parameters included:

   1. Seat tightness/leakage characteristics,

2. Set pressure,

3. Opening and closing response time,

4. Blowdown,

5. Safety/relief valve lift-achieving rated flow capacity lift during each activation,

6. Safety/relief valve reclosure without chattering, disc oscillation, or sticking open, and

7. Capability to open without inlet steam when activated on demand.

Test conditions were varied according to facility capability to ensure valve operability across the design limits to which the SRV may be subjected while in service. These included temperature, pressure ramp rates, pneumatic operating pressure, solenoid voltage, inlet pressure, and the dynamically imposed backpressure.

Test results indicate essentially zero leakage for both the relief (power) and safety (pressure) modes of SRV operation. All valves demonstrated seat-tightness capability to meet the 20 lb/hr specification limit under saturated steam conditions. Each valve demonstrated safety actuation within the nameplate value plus 1% at a confidence level of 0.95. The response is also linear with ambient temperature in the negative direction; i.e., at temperatures above 135°F the actual pop pressure is lower than the nameplate value. The temperature correction value is 0.2 psi/°F for this SRV. Set pressure is independent of ramp rate variance. Response of the SRV is directly related to the effective differential pressure force acting to open the SRV; therefore, outlet static pressure at the exit can be accurately accounted for.

Opening times were as follows during the test set up:

Safety actuation time - $0.020 \leq t \leq 0.30$ sec

Relief actuation time - $0.020 \leq t \leq 0.15$ sec

Actual installation times could result in a delay time >0.10 sec due to wire lengths and other non-SRV wire losses. Closing times were:

Safety actuation - none, controlled by blowdown requirement.

Relief actuation -	time to deenergize solenoid	< 0.90 sec
	disc travel after solenoid was deenergized	< 1.50 sec

Blowdown within the required range of 2% to 11% was demonstrated. Each SRV is adjusted by full flow testing for acceptable blowdown.

Qualification test results demonstrate the SRV will open to rated capacity lift in either the relief or safety modes of operation when actuated.

The SRV reclosure was demonstrated throughout the qualification tests without sticking, chatter, or disc oscillation during the closure stroke. When inlet pressure was increased to repressurize to the set pressure, the SRV reactuated to the full open position. The modified SRV will open to its full rated capacity lift position when operated in the relief mode with the inlet pressure at zero psig, thus demonstrating its emergency operability capability.

Six SRVs were included in this life cycle qualification test program. Test anomalies corrected during this demonstration do not invalidate the adequacy of the test results obtained; the finalized modified SRV design is considered acceptable for BWR main steam applications.

b. Seismic and Moment Transfer Test

One valve specimen was subjected to operating basis earthquake (OBE) and safe shutdown earthquake (SSE) accelerations and flanged end connection moment loading with valve inlet pressurized with saturated steam. Valve operability was demonstrated during and after application of loading. Maximum test loads were 8×10^5 in. pound moment at valve inlet and 6×10^5 in. pound moment at valve outlet. Seismic accelerations of 5.0g horizontal and 4.2g vertical are the established maximum for any frequency between 5 to 200 Hz unless otherwise specified for a smaller frequency range.

c. Emergency Environmental Qualification Test

The solenoid valves and the pneumatic actuator assembly were subjected to a test sequence as follows:

1. Thermal aging equivalent to 343°F for 96 hours,

2. Radiation aging to greater than or equal to 30×10^6 rads,

3. Mechanical aging for 1000 cycles (500 per solenoid),

4. Seismic testing as described in item b. above,

5. Exposure to emergency environmental conditions of 340°F at 65 psig decreasing to 250°F at 25 psig for 4 days, and

6. Separate solenoid valve test

Separate solenoid valve test	340°F, 3 hrs, 45 psig
	320°F, 3 hrs, 45 psig
	250°F, 18 hrs, 25 psig
	200°F, 99 days, 20 psig.

Operability of the actuator assembly was demonstrated during and after exposure to the emergency environment.

d. Low-Pressure Water Discharge Test

Low-pressure water discharge tests as described and reported in GE Report NEDE-24988 to satisfy the requirements of II.D.1 of NUREG-0737.

Test reports/records of the above qualification tests are available for inspection.

Each SRV is production tested at the vendor's shop to ensure, by demonstration, each SRV manufactured will reliably perform its required function(s). The SRV production test consist of

a. Inlet and outlet hydrostatic tests at specified conditions to satisfy ASME Code requirements,

b. Emergency operability test to verify capability of actuator to open the SRV without inlet pressure applied to the valve,

c. Actuator system leakage test to assure pneumatic leaktightness is compatible with plant air system make-up requirements,

d. Nitrogen set pressure and leakage test to rough adjust setpoint and ensure seat quality of seating surface prior to steam tests (optional),

e. Set pressure and blowdown test under thermally stabilized and saturated steam conditions,

f. Response time tests to verify relief opening and closing times under thermally stabilized and saturated steam conditions, and

g. Steam leakage tests to verify leaktightness.

The valves are normally installed as received from the factory providing there is no apparent evidence of damage during transportation, handling, and storage. For valves stored longer than one year, it is recommended they be recertified to ensure operability. The GE equipment specification requires certification from the valve manufacturer that design and performance requirements have been met.

Testing to satisfy the ASME Code requirements is normally performed in situ. Testing can be performed locally or remotely. The local test method is conducted using a test fixture that is temporarily mounted on the SRV and then removed on completion of the test. Remote testing is accomplished using a permanently mounted pneumatic head assembly that is controlled by a remote computer. This method does not require any personnel entry into the containment for the purpose of testing.

During the startup test program, all of the main steam SRVs were tested for proper operation. These tests include a documentation review to ensure that the valves were properly installed, properly handled during transportation, storage, and installation, and were properly maintained as to cleanliness prior to performance of any tests. In addition, the air accumulator capacity, SRV nameplate set pressure, and capacity were compared with the system design documentation for compliance.

Actual mechanical tests included an operability check of the SRV discharge line vacuum breakers, actuation of the individual SRVs by each remote manual switch (main control room and/or remote shutdown panel) to demonstrate full lift, smooth stroke, and opening time characteristics, actuation of each SRV in the relief mode by stimulating its pressure switch, and a demonstration that each SRV accumulator (ADS and/or normal) has sufficient capacity to operate the SRV air actuator as required by the system design documentation. Finally, the ADS logic was fully tested for proper performance. Note that only the air actuator was exercised during many of the startup tests. This minimizes valve wear and unnecessary maintenance.

During the power ascension phase of the startup test program, each SRV was manually actuated at approximately 250 psig reactor pressure to demonstrate valve operability. At approximately 50% power each SRV was actuated a second time to measure discharge capacity and to demonstrate that no blockage in the SRV discharge line existed.

At commercial turnover the scope of SRV testing was governed by ASME B&PV Code Section XI, Article IWV and the Technical Specifications. This article specifies the rules and requirements for inservice testing to verify operational readiness of the SRVs. This code section is applied to both ADS and non-ADS valves alike. Supplemental tests of the ADS

valves each operating cycle are required by the Technical Specifications. Applying Section XI, the SRV test schedule (in part) is as follows:

Time Period (Cycle)	Number of Valves Tested	Total Tested	Elapsed Time (years)
1	6	6	1.5
2	4	10	2.5
3	4	14	3.5
4	4	18	4.5
5	4	4	1.0
6	4	8	2.0
7	4	12	3.0
8	4	16	4.0
9	2	18	5.0

Note that following the return to service of the testing SRVs, an operability demonstration will be performed in compliance with Section XI, Article IWV-3200.

This combination of the startup test program, Technical Specifications surveillance, and inservice inspection testing satisfies industry standards for SRV operability demonstrations. Energy Northwest participated in the BWR Owners' Group for TMI concerns on SRV reliability. The final test program description was submitted to the NRC by the BWR Owners' Group and is endorsed by Energy Northwest.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specifications

Table 5.2-7 lists the principal pressure retaining materials and the appropriate material specifications for the RCPB components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Pressurized Water Reactor Chemistry of Reactor Coolant

Not applicable to BWRs.

5.2.3.2.2 Boiling Water Reactor Chemistry of Reactor Coolant

Regulatory Guide 1.56 compliance is addressed in Section 1.8.

Reactor feedwater (RFW) quality is maintained in accordance with the Licensee Controlled Specifications (LCS) and as described in Section 10.4.6.

Materials in the primary system are primarily austenitic stainless steel and Zircaloy cladding. The reactor water chemistry limits are established to provide an environment favorable to these materials. Limits are placed on conductivity and chloride concentrations. Conductivity is limited because it can be continuously and reliably measured and gives an indication of abnormal conditions and the presence of unusual materials in the coolant. Chloride limits are specified to prevent stress corrosion cracking of stainless steel. For further information, see Reference 5.2-2.

Periodically an On-Line NobleChem™ application will be performed to create a catalytic layering of the noble metal platinum to reduce the hydrogen injection rate required to achieve a low electrochemical corrosion potential (ECP). The low ECP achieves intergranular stress corrosion cracking (IGSCC) and irradiation assisted stress corrosion cracking (IASCC) protection while minimizing the effects of high dose rates attributed to regular hydrogen injection rates.

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

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

A reactor water cleanup (RWCU) system is provided for removal of feedwater input impurities plus corrosion and fission products originating from primary system components. The cleanup process consists of filtration and ion exchange and serves to maintain a high level of water purity in the reactor coolant.

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

An iron addition system is used to inject an iron oxalate/demineralized water solution into the suction line of the condensate booster pumps. The injection flow rate is extremely small when compared to condensate system flow rate. This iron injection system will have a negligible affect on the oxygen concentration in the RFW.

A hydrogen injection system is installed across the condensate booster pumps. This hydrogen injection system will have a negligible affect on the oxygen concentration in the RFW.

No other inputs of water or sources of oxygen are present during normal plant operation. During plant conditions other than normal operation, additional inputs and mechanisms are present as reactor coolant water could contain up to 8 ppm dissolved oxygen.

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

Grab sample points are provided at the locations shown in Table 5.2-8, for special measurements such as pH, oxygen, chloride, and radiochemical content.

The relationship of chloride concentration to specific conductance measured at 25°C for chloride compounds such as sodium chloride and hydrochloric acid can be calculated (see Figure 5.2-10). Values for these compounds essentially bracket values of other common chloride salts or mixtures at the same chloride concentration. Surveillance requirements are based on these relationships.

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

The sampling frequency established for primary coolant at normal conductivity levels is adequate for instrument checks and routine audit purposes. When specific conductance increases and higher chloride concentrations are possible or when continuous conductivity monitoring is unavailable, sampling frequency is increased according to LCS.

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

Water Purity During a Condensate Leakage

Due to improved water quality limits, any appreciable circulating water inleakage would result in water chemistry conditions outside acceptable limits and require action(s) to return the water quality to within applicable limits for continued plant operation.

5.2.3.2.3 Compatibility of Construction Materials with Reactor Coolant

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

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

b. Nickel base alloys - Inconel 600 and Inconel X750 and Inconel 82 and 182 weld metal,

c. Carbon steel and low alloy steel,

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

e. Cobalt, chromium, nickel, and iron based alloy hardfacing material

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

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

The recirculation system piping and normally flooded sections of the reactor vessel are coated as needed utilizing the GEH On-Line NobleChem™ application process with a microscopic layer of noble metals. This coating serves to prevent as well as mitigate IGSCC by eliminating the dissolved oxygen at the metal surface when an amount of hydrogen gas is added in a molar ratio of greater than 2 to 1 hydrogen to oxygen.

Type 304 stainless steel has been replaced with type 316L stainless steel in the recirculation inlet line safe ends. The bypass lines and the CRD hydraulic return line were eliminated and nozzles capped. The core spray lines are fabricated of carbon steel. The piping components that do not comply with the requirements of the Generic Letter 88-01 (GL 88-01), NRC Position on IGSCC BWR austenitic Stainless Steel Piping, will be subjected to the augmented inspection requirements of GL 88-01 as modified in Energy Northwest response (see Section 5.2.4 and Tables 5.2-9 and 5.2-10).

5.2.3.2.4 Compatibility of Construction Materials with External Insulation and Reactor Coolant

The materials of construction exposed to external insulation are

a. Solution annealed austenitic stainless steels (e.g., types 304, 304L, and 316), and

b. Carbon and low alloy steel.

Two types of external insulation are used. Reflective metal insulation used does not contribute to any surface contamination and has no effect on construction materials. The fibrous insulation used meets the requirements of Regulatory Guide 1.36.

DZO and iron are additives in the BWR coolant. Leakage would expose materials to high purity demineralized water, DZO, and iron. Exposure to demineralized water, DZO, and iron would cause no detrimental effects.

5.2.3.3 <u>Fabrication and Processing of Ferritic Materials and Austenitic Stainless Steels</u>

Fracture toughness requirements for the ferritic materials used for piping and valves (no ferritic pumps in RCPB) of the RCPB were as follows:

Safety/relief valves were exempted from fracture toughness requirements because Section III of the 1971 ASME B&PV Code did not require impact testing on valves with inlet connections of 6 in. or less nominal pipe size.

Main steam isolation valves were also exempted because the mandatory ASME Code, 1971 Edition through the Winter 1971 Addenda, required brittle fracture testing on ferritic pressure

boundary components only if required in the Design Specification. The Design Specification did not require brittle fracture testing because the system temperature is in excess of 250°F at pressure above 20% of the design pressure. Material information pertaining to the MSIVs is contained in Table 5.2-11.

Main steam piping was tested in accordance with and met the fracture toughness requirements of Paragraph NB-2300 of the 1972 Summer Addenda to ASME Code, Section III.

The ferritic pressure boundary material of the RPV was qualified by impact testing in accordance with the 1971 Edition of Section III ASME Code and Addenda to and including the Summer 1971 Addenda.

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

The degree of compliance with Regulatory Guides 1.31, 1.34, 1.37, 1.43, 1.44, 1.50, 1.66, and 1.71 is addressed in Section 1.8.

5.2.4 INSERVICE INSPECTION AND TESTING OF THE REACTOR COOLANT PRESSURE BOUNDARY

The structural integrity of ASME Code Class 1, 2, and 3 components are maintained as required by the ISI program in accordance with 10 CFR 50.55a. With the structural integrity of any component not conforming to the above requirements, the structural integrity will be restored to within its limits or the affected component will be isolated. For Class 1 components, this isolation will be accomplished prior to increasing reactor coolant system temperature more than 50°F above the minimum temperature required by nil-ductility transition (NDT) considerations. For Class 2 components, isolation will be accomplished prior to increasing reactor coolant system temperature above 200°F.

Inservice Inspections are performed in accordance with the requirements of 10 CFR 50.55a subparagraph (g) as described in the Inservice Inspection Program Plan.

5.2.4.1 System Boundary Subject to Inspection

The system boundary subject to inspection is defined in the Inservice Inspection Program Plan. *The RPV was examined prior to service in accordance with the requirements of the 1974 Edition of the ASME B&PV Code, Section XI, including the Summer 1975 Addenda. All Class 1 piping, pumps, and valves were examined prior to service in accordance with the requirements of the 1974 Edition of the ASME B&PV Code, Section XI, with Addenda through Summer 1975, including Appendix III from the Winter 1975 Addenda.*

The design of the RPV shield wall and external inservice inspection system was completed prior to the promulgation of amendments to 10 CFR 50.55a which require the upgrading of the

utility's inservice inspection code commitment for examinations subsequent to the baseline examination. The design has allowed some additional access for inspections and coverages anticipated to be required by later codes, where possible. The result of this effort has increased the areas on the RPV available to inservice inspection (approximately 84% of the vessel weld volume is accessible) and has allowed the piping examination to be upgraded to conform to the requirements of the Summer 1975 Addenda to Section XI as far as practical.

The preservice examination was performed on Class 1 components and piping pursuant to the requirements of the 1974 Edition of the ASME B&PV Code, Section XI, including the Summer 1975 Addenda for both the RPV and associated piping, pumps, and valves. It is described in the Preservice Inspection Program Plan (Reference 5.2-6).

5.2.4.2 Arrangement of Systems and Components to Provide Accessibility

Access for the purpose of inservice inspection is defined as the design of the plant with the proper clearances for examination personnel and/or equipment to perform inservice examinations. The RCPB for the RPV is designed to provide compliance with the provisions for access as required by Subarticle IWA-1500 of the 1974 Edition of the ASME B&PV Code, Section XI, including the Summer 1975 Addenda. The RCPB for piping, pumps, and valves is designed to provide compliance with the provisions for access as required by Subarticle IWA-1500 of the 1974 Edition of the ASME B&PV Code, Section XI, with addenda through Summer 1975.

Access is provided for volumetric examination of the pressure containing welds from the external surfaces of components and piping by means of removable insulation, removable shielding, and permanent tracks for remote inspection devices in areas where personnel access is restricted. The provisions for suitable access for inservice inspection examinations minimizes the time required for these inspections and, hence, reduces the amount of radiation exposure to both plant and examination personnel. Working platforms are provided at most strategic locations in the plant which permit ready access to those areas of the RCPB which are designated as inspection points in the inservice inspection program. Temporary scaffolding will be used as required to gain access for examination.

Energy Northwest retained Southwest Research Institute to provide an independent assessment as to the suitability of plant access provisions for inservice inspection. This overview provided for identification of design modification or inspection technique development needs to ensure maximum practical compliance with code requirements.

5.2.4.2.1 Reactor Pressure Vessel

Access for inspection of the RPV is as follows:

a. *Access to the exterior surface of the RPV for inservice inspection is provided by removable insulation and shield plugs. Hinged shield wall plugs around nozzles are used to gain access for nozzle inspection. A minimum annular space of 8.25 in. is provided between the vessel exterior surface and the insulation interior surface to permit the insertion of remotely operated inspection devices between the insulation and the reactor vessel. The RPV nozzle insulation is removable. This design allows sufficient clearances for the mounting of a nozzle-to-shell examination device from tracks located either at the nozzle safe-end or at the pipe area. Examinations that can be performed from these tracks include the required coverage of the nozzle-to-shell welds and depending on technique, could provide examination coverage of the nozzle inner radius section and nozzle-to-safe-end weld. Access, geometry and radiation level considerations will determine those nozzles scheduled for manual examination.*

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

c. *The closure head is dry stored during refueling which facilitates direct manual examination. Removable insulation allows examination of the head welds from the outside surface. Reactor vessel nuts and washers are removed to dry storage for examination during refueling.*

   Selected studs are examined during refueling in accordance with the Inservice Inspection Program Plan.

d. Openings in the RPV support skirt are provided to permit access to the RPV bottom head for purposes of inservice examination. The examinations performed include volumetric examinations of circumferential welds, portions of the meridional welds, portions of the dollar plate longitudinal welds, and visual examination of accessible penetration welds.

5.2.4.2.2 Piping, Pumps, and Valves

The physical arrangement of piping, pumps, and valves is designed to allow personnel access to welds requiring inservice inspection. Modifications to the initial plant design have been incorporated where practicable to provide inspection access on Class 1 piping systems. Removable insulation is provided on those piping systems requiring inspection. In addition, the placement of pipe hangers and supports with respect to those welds requiring inspection have been reviewed and modified where necessary to reduce the amount of plant support required in these areas during inspection. Working platforms are provided to facilitate servicing most of the pumps and valves. Temporary platforms, scaffolding, and ladders will be provided to gain additional access for piping and some pump and valve examinations. An effort has been made to minimize the number of fitting-to-fitting welds within the inspection boundary. Welds requiring inspection are located to permit ultrasonic examinations from at least one side, but where component geometries permit, access from both sides of the weld is provided. The surface of welds within the inspection boundary are prepared to permit effective ultrasonic examination.

5.2.4.3 Examination Techniques and Procedures

Examination techniques and procedures for the preservice examination, including any special technique and procedure, met the requirements of Table IWB-2600 of the 1974 Edition of the ASME B&PV Code, Section XI, including the Summer 1975 Addenda for both the RPV and the associated piping, pump, and valve examinations. Examination techniques and procedures for inservice inspections are in accordance with the Inservice Inspection Program Plan. *During plant design, an effort was made to upgrade the requirement for calibration standards. Where upgrading was not feasible, material of the same P series with similar acoustic characteristics were used.*

5.2.4.3.1 Equipment for Inservice Inspection

Access for inservice inspection of the RPV seam welds is accomplished through openings in the sacrificial shield. These openings are provided at each nozzle location. Permanently installed tracks between the vessel surface and the insulation can be used for mounting remotely operated devices. Access is also provided for devices that do not require use of these tracks.

Remote ultrasonic scanning equipment for examination of the nozzle-to-vessel welds will be supported and guided from tracks temporarily mounted on the pipe connected to the nozzle. The examination equipment will provide radial and circumferential motion to the ultrasonic transducer while rotating about the nozzle. Installation of the equipment will be accomplished through the access openings in the sacrificial shield which are provided at each nozzle location.

5.2.4.3.2 Coordination of Inspection Equipment With Access Provisions

Access to areas of the plant requiring inservice inspection is provided to allow use of standard equipment wherever practicable. Design in general provides for free space envelopes both radially and axially from welds to be examined so standard manual examination equipment may be utilized. Any special equipment or techniques used will achieve the sensitivities required by the codes.

5.2.4.3.3 Manual Examination

In areas where manual ultrasonic examination is performed, all reportable indications are recorded consistent with current inservice inspection codes in effect. Radiographic techniques may be used where ultrasonic techniques are not practical. In areas where manual surface or direct visual examinations are performed, all recordable indications will be in accordance with the Inservice Inspection Program Plan.

5.2.4.4 Inspection Intervals

Inspection intervals are defined in the Inservice Inspection Program Plan.

5.2.4.5 Examination Categories and Requirements

Examination categories and requirements for the preservice inspection are defined in the Preservice Inspection Program Plan and closely follow the categories and requirements specified in Tables IWB-2500 and IWB-2600 of the 1974 Edition with Addenda through Summer 1975 of the ASME B&PV Code, Section XI, for the RPV and the associated piping, pumps, and valves.

Examination categories and requirements for inservice inspections are in accordance with the requirements of ASME Section XI and are contained in the Inservice Inspection Program Plan.

5.2.4.6 Evaluation of Examination Results

Evaluation of results for the RPV, pump, and valve baseline examinations were conducted in accordance with Article IWB-3000 of the 1974 Edition of the ASME B&PV Code, Section XI, including the Summer 1975 Addenda. Evaluation of examination results for piping baseline examinations were conducted in accordance with Article IWB-3000 of the 1974 Edition of the ASME B&PV Code, Section IX, with Addenda through Winter 1975. Energy Northwest recognized that Section XI had been promulgated as an effective code by 10 CFR 50.55a, for the baseline examinations, only through the Summer 1975 Addenda. However, Energy Northwest also recognized that even though the code through Summer 1975 Addenda included evaluation criteria which could be interpreted to apply to piping (Category B-J) welds, the evaluation criteria found in the Winter 1975 Addenda clearly provides evaluation criteria which

are applicable to these welds. Energy Northwest was unaware that the NRC staff was opposed to these evaluation criteria and anticipates that the criteria which will appear in the future codes will be consistent therewith. Evaluations are performed in accordance with the Inservice Inspection Program Plan.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

The requirement for baseline hydrostatic test for the RPV was satisfied by the hydrostatic test performed in accordance with the requirements of ASME Section III. Similarly, the requirements for the baseline piping system leakage and hydrostatic tests were satisfied by reference to the Section III hydrostatic test report as permitted by ASME Section XI, IWA-5210(b). Subsequent hydrostatic and system leak tests are conducted to the code in effect in accordance with the Inservice Inspection Program Plan.

5.2.4.8 Inservice Inspection Commitment

All quality Group A components were examined once prior to startup in accordance with the above requirements. This preoperational examination served to satisfy the requirements of IWB-2100 of the 1974 Edition of the ASME B&PV Code, Section XI, including the Summer 1975 Addenda for the RPV and associated piping, pumps, and valves. Inservice inspection of Columbia Generating Station is performed in accordance with the Inservice Inspection Program Plan.

5.2.4.9 Augmented Inservice Inspection to Protect Against Postulated Piping Failures

An augmented Inservice Inspection Program Plan has been implemented for Columbia Generating Station, on high energy* Class 1 piping systems which penetrate containment for which the effects of postulated pipe breaks would be unacceptable. This program is described in the Inservice Inspection Program Plan.

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* High-energy lines include those systems that, during normal plant conditions, are either in operation or maintained pressurized and where either the maximum operating pressure exceeds 275 psig or maximum operating temperature exceeds 200°F. If, for a particular line, the above pressure and temperature limits are not exceeded more than 2% of the time that the system is in operation, then that line is considered moderate energy and is exempt from the requirement for augmented inservice inspection.

5.2.4.10 Augmented Inservice Inspection of Reactor Pressure Vessel Feedwater Nozzles

5.2.4.10.1 Preservice Examination

Energy Northwest performed a preservice inspection ultrasonic examination of the RFW nozzle inner radii, bore, and safe end regions as described in the Preservice Inspection Program Plan.

In addition, a preservice liquid penetrant examination was performed on the accessible areas of all RFW nozzle inner radius surfaces.

5.2.4.10.2 Inservice Examination

Inservice examinations of RFW nozzles are performed in accordance with the Inservice Inspection Program Plan.

5.2.4.11 Augmented Inservice Inspection for Intergranular Stress Corrosion Cracking

Energy Northwest performed an ultrasonic examination of all Code Class 1 piping which is considered susceptible to IGSCC. The results are reported in the Preservice Inspection Summary Report (References 5.2-9 and 5.2-10).

GL 88-01 weld categories and augmented inspection requirements are described in the Inservice Inspection Program Plan.

5.2.4.12 ASME Section XI Repairs/Replacements

The repair or modification of N-stamped components will be performed in accordance with the Edition and Addenda of ASME Section XI defined in the Inservice Inspection Program Plan and in accordance with ASME Section III (Code Edition and Addenda to which the component was fabricated).

Deviations to the above referenced code edition and addenda as allowed by code will be reviewed by Energy Northwest and authorized on a case-by-case basis.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

5.2.5.1 Leakage Detection Methods

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

a. Main steam lines,
b. RWCU system,
c. RHR system,
d. Reactor core isolation cooling (RCIC) system,
e. Feedwater system,
f. HPCS,
g. LPCS, and
h. Coolant system within the primary containment.

Isolation and/or alarm of affected systems and the detection methods used are summarized in Table 5.2-12.

Small leaks (5 gpm and less) are detected by temperature and pressure changes, drain sump pump activities, floor drain flow monitoring, and fission product monitoring. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

The 5-gpm leakage rate is the limit on unidentified leakage. The leak detection system sensitivity and response is discussed in Section 7.6.2.4.

Compliance with Regulatory Guide 1.45 is described in Section 1.8.

Table 5.2-12 summarizes the actions taken by each leakage detection function. The table shows that those systems which detect gross leakage initiate immediate automatic isolation. The systems which are capable of detecting small leaks initiate an alarm in the control room. The operator can manually isolate the violated system or take other appropriate action.

5.2.5.1.1 Detection of Abnormal Leakage Within the Primary Containment

Leaks within the drywell are detected by monitoring for abnormally high-pressure and temperature within the drywell, high fillup rates of equipment and floor drain sumps, excessive temperature difference between the inlet and outlet cooling water for the drywell coolers, a decrease in the reactor vessel water level, and high levels of fission products in the drywell atmosphere. Temperatures within the drywell are monitored at various elevations. Also the temperature of the inlet and exit air to the atmosphere is monitored. Excessive temperatures in

the drywell, increased drywell drain sump flow rate, and drywell high-pressure are annunciated by alarms in the control room. Drywell high pressure and low reactor vessel water level will cause automatic primary containment isolation. In addition, low reactor vessel water level will isolate the main steam lines. The systems within the drywell share a common area; therefore, their leakage detection systems are common. Each of the leakage detection systems inside the drywell is designed with a capability of detecting leakage rates less than those established by the Technical Specifications.

5.2.5.1.2 Detection of Abnormal Leakage Outside the Primary Containment

Outside the drywell, the piping within each system monitored for leakage is in compartments or rooms, separate from other systems where feasible, so that leakage may be detected by area temperature indications. Each leakage detection system discussed in the following paragraphs is designed to detect leak rates that are less than those established by the Technical Specifications. The method used to monitor for leakage for each RCPB component is described in Table 5.2-12.

a. Ambient and differential room ventilation temperature

A differential temperature sensing system is installed in each room containing equipment that is part of the RCPB. These rooms are the RCIC, RHR, and the RWCU systems equipment rooms and main steam line tunnel. Temperature sensors are placed in the inlet and outlet ventilation ducts or across room boundaries. Other sensors are installed in the equipment areas to monitor ambient temperature. A differential temperature monitor reads each set of sensors and/or ambient temperature and initiates an alarm and isolation when the temperature reaches a preset value. Annunciator and remote readouts from temperature sensors are indicated in the control room.

Spurious isolations of systems due to a relatively sharp drop in outside ambient temperature is highly unlikely. For example, the normal approximate operating differential temperature for the RHR and RCIC pump rooms is 26°F and 32°F respectively. The temperature elements are located at the face of the supply and return ductwork in each pump room. The setpoint differential for isolation is 50°F and 55°F for RCIC and RHR to allow for heat released from a predetermined steam leak. Analysis has shown that it would take a 30°F/hr ambient (outside) temperature decrease for about 2 hr to cause isolation. This magnitude of temperature drop is not supported historically because meteorological data for Hanford has not recorded changes of this magnitude.

b. Reactor building sump flow measurement

Instrumentation monitors and indicates the amount of leakage into the reactor building floor drainage system. The normal leakage collected in the system consists of leakage from the RWCU and CRD systems and from other miscellaneous vents and drains.

c. Visual and audible inspection

Accessible areas are inspected periodically and the temperature and flow indicators discussed above are monitored regularly as required by the Technical Specifications. Any instrument indication of abnormal leakage will be investigated.

d. Differential flow measurement (cleanup system only)

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

5.2.5.2 Leak Detection Devices

a. Drywell floor drain sump measurement

The normal design leakage collected in the floor drain sump consists of leakage from the CRDs, valve flange leakage, floor drains, closed cooling water system drywell cooling unit drains, and potential valve stem leaks. The floor drain sump collects unidentified leakage. Design details are given in Section 9.3.3.

b. Drywell equipment drain sump

The equipment drain sump collects only identified leakage. This sump receives condensate drainage from pump seal leakoff and the reactor vessel head flange vent drain. Collection in excess of background leakage would indicate reactor coolant leakage. Design details are given in Section 9.3.3.

c. Drywell air sampling

The primary containment radiation monitoring system is used to supplement the temperature, pressure, and flow variation method described previously to detect

leaks in the nuclear system process barrier. This system is described in Sections 11.5 and 7.6.

Radiation monitors are useful as leak detection devices because of their sensitivity and rapid response to leaks. After several weeks of full power operation, a set level of background radiation is established. Any sudden or unexplained increase in background radiation indicates a possible primary coolant leak within the primary containment. If an increase is noted, a comparison with other leak detection devices having a relationship to each other is made, particularly the equipment and floor drain flow rate monitors, and the reactor building sump pumps activation on high sump level. Using the flow rate monitors as a reference, the comparisons provide independent indications of a leak within the primary containment. This provides diversity in leak detection.

d. Reactor vessel head closure

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

e. Reactor water recirculation pump seal

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

f. Safety/relief valves

Tail pipe temperature sensors connected to a multipoint recorder are provided to detect SRV leakage during reactor operation. Safety/relief valve temperature elements are mounted, using a thermowell, in the SRV discharge piping several feet from the valve body. Temperature rise above ambient is recorded in the main control room.

5.2.5.3 Indication in the Control Room

Details of the leakage detection system indications are included in Section 7.6.1.3.

5.2.5.4 Limits for Reactor Coolant Leakage

5.2.5.4.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The total leakage rate limit is established so that, in the absence of normal ac power with loss of feedwater supply, make-up capabilities are provided by the RCIC system.

The equipment sump and the floor drain sump collect all leakage. The equipment sump is drained by one 50-gpm pump and the floor drain sump is drained by two 50-gpm pumps. The total leakage rate limit from inside containment is established at 25 gpm, which includes no more than 5 gpm unidentified leakage. The total leakage rate limit is low enough to prevent overflow of the drywell sumps.

5.2.5.4.2 Normally Expected Leakage Rate

The pump packing glands and other seals in systems that are part of the RCPB and from which normal design leakage is expected, are provided with drains or auxiliary sealing systems. Nuclear system pumps inside the drywell are equipped with double seals. Leakage from the primary recirculation pump seals is piped to the equipment drain sump. Leakage in the discharge lines from the main steam SRVs is monitored by temperature sensors that transmit a signal to the control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage.

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

The identified leakage is measured continuously and the leakage rate will be calculated and recorded on a frequency of at least once per 12 hr in accordance with the Technical Specifications. The procedures describing how the identified leakage rate is determined include provisions for showing the identified leakage rate has not exceeded the maximum allowable value of 25 gpm, including no more than 5 gpm unidentified leakage.

Each equipment leak-off connection has been provided with a temperature element which will identify to the operator that a higher than normal temperature exists at that particular location.

5.2.5.5 Unidentified Leakage Inside the Drywell

5.2.5.5.1 Unidentified Leakage Rate

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

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

The unidentified leakage rate limit is established at the 5-gpm rate to allow time for corrective action before the process barrier could be significantly compromised.

The following indications are available to the control room operator for evaluating and detecting unidentified leakage:

Drywell pressure recorders,
Drywell temperature recorders,
Drywell floor drain total flow recorder,
Reactor building floor drain sump fillup rate timer,
Reactor building floor drain sump pump out rate timer,
Drywell cooler cooling water differential temperature recorder,
Reactor vessel water level, and
Drywell atmosphere radiation monitors.

While the indications listed above have no definitive correlation between their engineering units, they provide an early warning of a potential leak to the operator. The actual unidentified leak rate is determined by observing the drywell floor drain system flow rate recorders provided in the control room. Since the monitoring is not computerized, a computer failure would not affect indications.

5.2.5.5.2 Length of Through-Wall Flaw

Experiments conducted by GE and Battelle Memorial Institute (BMI) permit an analysis of critical crack size and crack opening displacement (References 5.2-4 and 5.2-5). This analysis relates to axially oriented through-wall cracks and provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is significantly greater than the 5-gpm criterion.

If either the total or unidentified leak rate limits are exceeded, an orderly shutdown would be initiated and the reactor would be placed in a cold shutdown condition in accordance with the Technical Specifications.

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

For process lines that are normally open, there are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier located in the drywell, reactor building, and auxiliary building as shown in Table 5.2-12. The instrumentation is designed so it can be set to provide alarms at established leakage rate limits and isolate the affected system, if necessary. The alarm points are determined analytically or based on measurements of appropriate parameters made during startup and preoperational tests. Some alarm points require hot operation data for their determination. Preoperational testing verified proper operation of the instrumentation for the alarm point used.

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

The leak detection system sensitivity and response time is discussed in Section 7.6.2.4 such that an unidentified leakage rate increase of 1 gpm in less than 1 hr will be detected.

5.2.5.6 Safety Interfaces

The balance of plant/GE nuclear steam supply system safety interfaces for the leak detection system are the signals from the monitored balance-of-plant equipment and systems that are part of the nuclear system process barrier and associated wiring and cable lying outside the nuclear steam supply equipment. These balance-of-plant systems and equipment include the main steam line tunnel, the SRVs, and the turbine building sumps.

5.2.5.7 Testing and Calibration

Provisions for testing and calibration of the leak detection system are described in Section 7.6.

5.2.6 REFERENCES

5.2-1 "Qualification of the One–Dimensional Core Transient Model (ODYN) for BWR's," NEDO-24154–A, Vol. 1 and 2, General Electric, August 1986.

5.2-2 J. M. Skarpelos and J. W. Bagg, "Chloride Control in BWR Coolants," June 1973, NEDO-10899.

5.2-3 W. L. Williams, Corrosion, Vol. 13, 1957, p. 539t.

5.2-4 GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows," by M. B. Reynolds, April 1968.

5.2-5 "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," NUREG-76/067, NRC/PCSG, dated October 1975.

5.2-6 Washington Public Power Supply System, 1985, "WNP-2 Preservice Inspection Program Plan," Washington Public Power Supply System, Richland, Washington.

5.2-7 NEDE-32906P Supplement 3-A, "Migration to TRACG04/PANAC11 fromTRACG02/PANAC10 for TRACG AOO and ATWS Overpressure Transients," April 2010.

5.2-8 "Columbia Generating Station TRACG Implementation for Reload Licensing Transient Analysis," (T1309), 001N9271-R1, Revision 1, January 2015.

5.2-9 Letter GO2-85-110 from G. C. Sorenson, Supply System, to A. Schwencer, NRC, Subject: Nuclear Project No. 2, CPPR-93 Preservice Inspection Program Plan, Amendment No. 4, Summary Report Supplement No. 1, NIS-1 Code Data Report, dated February 28, 1985.

5.2-10 Letter GO2-83-401 from G. D. Bouchay, Supply System, to A. Schwencer, NRC, Subject: Nuclear Project No. 2, CPPR-93, Preservice Inspection Program Plan, Volume No. 4, "Preservice Inspection Summary Report", dated May 3, 1983.

5.2-11 "Supplemental Reload Licensing Report for Columbia" (most recent version referenced in COLR).

Table 5.2-1

Exceptions to Conformance to 10 CFR 50.55a
Reactor Coolant Pressure Boundary Components

Component Description	Quantity	Plant Identification System Number	Purchase Order Date	Code Applied ASME Section III	Code Required by 10 CFR 50.55(a)	Component Status
Main steam safety relief valves	18	MS-RV-1 A-D MS-RV-2 A-D MS-RV-3 A-D MS-RV-4 A-D MS-RV-5 B-C (B22-F013 A-V)	April 1971	1971 Edition	1971 Summer Addenda	FS[a]
Recirc pumps	2	RRC-P-1A (B35-C001)	April 1971	1971 Edition	1971 Summer Addenda	FS
Recirc gate valves	4	RRC-V-23/ RRC-V-67 (B35-F023/F067)	June 1971	1971 Edition	1971 Summer Addenda	FS
Recirc flow control valve	2	RRC-V-60 (B35-F060)	June 1971	1971 Edition	1971 Summer Addenda	FS
Recirc piping	1 lot	B35-G001	October 1971	1971 Summer Addenda	1971 Winter Addenda	FS

[a] FS = Fabricated and Shipped

Table 5.2-2

Reactor Coolant Pressure Boundary
Component Code Case Interpretations

	Number	Title	Remarks
1.	1332 - Revision 6	Requirements for steel forgings	Regulatory Guide 1.85, Revision 6
2.	1401 - Revision 0	Welding repairs to cladding of Class I, Section III, components after heat treating	
3.	1420 - Revision 0	5b-167 Ni-Cr-Fe alloy pipe or tube	
4.	1441 - Revision 1	Waiving of 3 S_m requirement for Section III construction	
5.	1141 - Revision 1	Foreign produced steel	Regulatory Guide 1.85, Revision 5
6.	1361 - Revision 2	Socket welds, Section III	Regulatory Guide 1.84, Revision 9
7.	1525	Pipe descaled by means other than pickling, Section III	
8.	1535 - Revision 2	Hydrostatic test of Class 1 nuclear valves, Section III	Regulatory Guide 1.84, Revision 9
9.	1567	Testing lots of carbon and low alloy steel covered electrodes, Section III	Regulatory Guide 1.85, Revision 6
10.	1621 - Revision 1	Internal and external valve items, Section III, Class 1	Regulatory Guide 1.84, Revision 12 (for 1621-2)
11.	1588	Electro-etching of Section III code symbols	Regulatory Guide 1.84, Revision 9
12.	1820	Alternative ultrasonic examination technique Section III, Division 1	Regulatory Guide 1.85, Revision 11
13.	N181	Steel castings refined by the argon oxygen decarbonization process Section 3, Division 1 construction	
14.	1711	Pressure relief valve, design rules, Section III, Division 1, Class 1, 2, 3	

Table 5.2-3

Nuclear System Safety/Relief Setpoints

Number of Valves	Spring Set Pressure (psig)	ASME Rate Capacity at 103% Spring Set Pressure (lb/hr each)	Pressure Setpoint for the Power Actuated Mode (psig)
2	1165	876,500	1091
4	1175	883,950	1101
4	1185	891,380	1111
4	1195	898,800	1121
4	1205	906,250	1131

Note: Seven of the safety/relief valves serve in the automatic depressurization function.

Table 5.2-4

Systems Which May Initiate During
Safety Valve Capacity Overpressure Event

System	Initiating/Trip Signal(s)[a]
Reactor Protection System	Reactor trips "OFF" on high flux
RCIC	"ON" when reactor water level ≤L2
	"OFF" when reactor water level ≥L8
HPCS	"ON" when reactor water level ≤L2
	"OFF" when reactor water level ≥L8
Recirculation system	"OFF" when reactor water level ≤L2
	"OFF" when reactor pressure ≤1143 psig
RWCU	"OFF" when reactor water level ≤L2

[a] Note: Vessel level trip settings L2 and L8 shown in Figure 5.3-3.

Table 5.2-5

Sequence of Events for Figure 5.2-2

Time-Sec	Event
0	Initiate closure of all main steam isolation valves (MSIV).
0.45	MSIVs reached 85% open and initiated reactor scram. However, hypothetical failure of this position scram was assumed in this analysis.
2.0	Neutron flux reached the high APRM flux scram setpoint and initiate reactor scram.
2.9	Steam line pressure reached the group safety relief valve pressure setpoint (spring-action mode and safety relief valves started to open).
3.0	MSIVs completely closed.
3.5	All safety relief valves opened.
3.9	Vessel bottom pressure reached its peak value.

Table 5.2-6

Design Temperature, Pressure and Maximum Test Pressure for RCPB Components

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Reactor vessel	575	1250	1563
Recirculation system			
Pump discharge piping, through valves	575	1650	(a)
Pump discharge piping, beyond valves	575	1550	(a)
Pump suction piping	575	1250	(a)
Pump and discharge valves	575	1650	(b)
Suction valves	575	1250	(b)
Flow control valve	575	1675	(a)
Vessel drain line	575	1275	(a)
Main steam system			
Main steam line	575	1250	(a)
Main steam line valves	575	1250	(b)
Residual heat removal system			
Shutdown suction			
Recirculation header to second isolation valve			
Piping	575	1250	(a)
Valves	575	1250	(b)
Pump discharge			
Reactor vessel to second isolation valve			
Piping	575	1250	(a)
Valves	575	1250	(b)

Table 5.2-6

Design Temperature, Pressure and Maximum Test Pressure for RCPB Components (Continued)

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure (psig)
Shutdown return			
Recirculation header to second isolation valve			
Piping	575	1575	(a)
Valves	575	1575	(b)
Reactor feedwater			
Reactor vessel to manual valve (F011)			
Piping	575	1300	(a)
Valves	575	1300	(b)
Reactor core isolation cooling system			
Steam to RCIC.	575	1250	(a)
Pump turbine			
Reactor vessel to second isolation valve			
Piping	575	1250	(a)
Valves	575	1250	(b)
Pump discharge to reactor	170	1500	(a)
Reactor vessel to second isolation valve			
Piping	575	1500	(a)
Valves	575	1500	(b)
High-pressure core spray system			
Outboard containment isolation valve to and including maintenance valve inside containment[c]			
Piping	575	1250	(a)
Valves	575	1250	(b)

Table 5.2-6

Design Temperature, Pressure and Maximum Test Pressure for RCPB Components (Continued)

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure (psig)
From maintenance valve to reactor vessel			
Piping	575	1250	(a)
Valves	575	1250	(b)
Low-pressure core spray system			
Outboard isolation valve to reactor vessel			
Piping	575	1250	(a)
Valves	575	1250	(b)
Standby liquid control			
Pump discharge to reactor vessel			
Reactor to second isolation valve[d]			
Piping	150	1400	(a)
Valves	150	1400	(b)
Reactor water cleanup system			
Pump suction			
Recirculation piping to isolation valve outside drywell			
Piping	575	1250	(a)
Valves	575	1250	(b)
Control rod drive system			
Piping to HCUs	150	1750	2187

[a] Test pressure at the bottom of the reactor vessel is nominally 1565. The piping is field tested with the reactor vessel.

[b] Test pressure is based on ASME III Table NB-3531-9 (1971 Edition through Winter 1973 Addenda).

[c] For dual design conditions, see Figure 6.3-3.1.

[d] The design temperature and pressure of the original injection piping were 575°F and 1250 psig. This portion of piping was rerouted to the HPCS injection and was tested in accordance with ASME Section XI, 1980 Edition, Winter Addenda.

Table 5.2-7

Reactor Coolant Pressure Boundary Materials

Component	Form	Material	Specification (ASTM/ASME)
Reactor vessel	Rolled plate	Low alloy steel	SA-533 grade B class 1
Heads, shells	Forgings Welds	 Low alloy steel	SA-508 class 2 SFA-5.5
Closure flange	Forged ring Welds	Low alloy steel Low alloy steel	SA-508 class 2 SFA-5.5
Nozzle safe ends	Forgings or Plates	Stainless steel	SA-182, F304 or F316 SA-336, F8 or F8 M SA-240, 304 or 316
	Welds	Stainless steel	SFA-519, TP-308L or 316L
Nozzle safe ends	Forgings Welds	Ni-Cr-Fe Ni-Cr-Fe	SB-166 or SB-167 SFA-5.14, TP ERNiCr-3 or SFA-5.11, TP ENCrFe-3
Nozzle safe ends	Forgings	Carbon steel	SA-105 grade 2, SFA-5.18 grade A, or SFA-5.17 F70
Nozzle safe ends	Forgings	Austenitic stainless steel	SA-182 grade F, 316L
Cladding	Weld overlay	Austenitic stainless steel	SFA-5.9 or SFA-5.4 TP-309 with carbon content on final surface limit to 0.09% maximum
Control rod drive housings	Pipe Forgings Welds	Austenitic stainless steel Inconel	SA-312 type 304 SFA-5.11 type ENiCrFe-3 or SFA-5.14 type ERNiCr-3

Table 5.2-7

Reactor Coolant Pressure
Boundary Materials (Continued)

Component	Form	Material	Specification (ASTM/ASME)
In-core housings	Pipe Forgings Welds	Austenitic stainless steel Inconel	SA-312 type 304 SFA-5.11 type ENiCrFe-3 or SFA-5.14 type ERNiCr-3

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

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

Pipe SA-106 grade B and C; SA-333 grade 5; SA-155 grade KCF 70

Valves SA-105 grade II-normalized; SA-350 grade LF1 or LF2 and SA-216 grade WCB, normalized; and SA-352 grade LCB

Fittings SA-105 grade II-normalized; SA-350 grade LF1 or LF2-normalized; SA-234 grade WPB-normalized; and SA-420 grade WPL1

Bolting SA-193 grade B7; and SA-194 grades 7 and 2H

Welding Material Welding materials conform to the applicable SFA specifications listed in ASME B&PV Code Section IIc. Individual selection of filter metals are reviewed for conformity to the base materials being welded by the Consulting Engineers' review of welding procedures.

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

Pipe SA-376 type 304; SA-312 type 304; SA-358 type 304

Valves SA-182 grade F-304 and F-316; SA-351 grades CF-3, CF-3M, CF-8 and CF-8M

Table 5.2-7

Reactor Coolant Pressure
Boundary Materials (Continued)

Pump	SA-182 grade F-304; SA-351 grades CF-8 and CF-8M
Flanges	SA-182 grade F-316
Bolting	SA-193 grade B7; SA-194 grades 7 and 2H
Welding	SFA-5.4 (E308-15, E308L-15, E316-15); SFA-5.9 (ER-308, ER-308L, ER-316)
Fittings	SA-182 grade F304; SA-351 grade CF-8; SA-403 grade WP-304, 304W

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Table 5.2-8

Water Sample Locations

Sample Origin	Sensor Location	Indicator Location	Recorder Location	Range μmho/cm	Alarm Low	Alarm High
Reactor water recirculation loop	Sample line	Sample station	Control room	0-1	0.0	1.0
Reactor water cleanup system inlet	Sample line	Sample station	Control room	0-1	0.0	1.0
Reactor water cleanup system outlets	Sample line	Sample station	Control room	0-0.3	NA	0.15

Table 5.2-9

IHSI Summary
Prior to First Refueling GL 88-01,
Category B Welds

Energy Northwest ISI Weld Number	Welds
Stainless steel to stainless steel	
24RRC(2)-A-2 thru 24RRC(2)-A-12	11
24RRC(1)-A-13 thru 24RRC(1)-A-22	10
16RRC(1)-A-1 thru 16RRC(1)-A-4	4
12RRC(1)-N2A-1, 1A	2
12RRC(1)-N2B-1, 1A	2
12RRC(1)-N2C-1, 1A	2
12RRC(1)-N2D-1, 1A	2
12RRC(1)-N2E-1, 1A	2
20RRC(6)-1 thru 20RRC(6)-7, 7A, 8	9
4RRC(8)-2A-1, 2	2
4RRC(8)-1A-1, 2	2
12RRC(7)-A-1 thru 12RRC(7)-A-6	6
12RHR(1)-A15 thru 12RHR(1)-A18	4
24RRC(2)-B-2 thru 24RRC(2)-B-10	9
16RRC(1)-B-1 thru 16RRC(1)-B-4	4
24RRC(1)-B-11 thru 24RRC(1)-B-20	10
12RRC(1)-N2F-1, 1A	2
12RRC(1)-N2G-1, 1A	2
12RRC(1)-N2H-1, 1A	2
12RRC(1)-N2J-1, 1A	2
12RRC(1)-N2K-1, 1A	2
4RRC(8)-2B-1, 2	2
4RRC(8)-1B-1, 2	2
12RRC(7)-B-1, 2, 2A thru 12RRC(7)-B-6	7
12RHR(1)-B-11 thru 12RHR(1)-B-13	3
20RHR(2)-1	1
Stainless steel to stainless steel caps	
24RRC(1)-A13/8CAP-1, A20/12CAP-1	2
24RRC(1)-B-11/CAP-1, 18/12CAP-1	2
Stainless steel to carbon steel	
20RHR(2)-2	1
12RHR(1)-A14	1
12RHR(1)-B-10	1
TOTAL	113

Table 5.2-10

IHSI Summary
During First Refueling GL 88-01,
Category B Welds

Energy Northwest ISI Weld Number		Welds
4RRC(4) A-1 thru 4RRC(4) A-11		11
4RRC(4) B-1 thru 4RRC(4) B-12		12
24RRC(2) A-10/4RRC(8)-4S		1
24RRC(2) A-10/4RRC(4)-4S		1
24RRC(1) A-13/4RRC(8)-4S		1
24RRC(1) A-13/8 Cap		1
24RRC(1) A-20/12 Cap		1
24RRC(1) A-20/12RRC(7)-4S		1
24RRC(2) B-8/4RRC(8)-4S		1
24RRC(2) B-8/4RRC(4)-4S		1
24RRC(1) B-11/8 Cap		1
24RRC(1) B-11/4RRC(8)-4S		1
24RRC(1) B-18/12 Cap		1
24RRC(1) B-18/12RRC(7)-4S		1
	TOTAL	35
Type 304 Welds with Low Carbon Content		
[a]4JP (NZ) A-1 Inconel 182 buttering		1
[a]4JP (NZ) B-1 Inconel 182 buttering		1
[a]4JP (NZ) A-2		1
[a]4JP (NZ) B-2		1
	TOTAL	4

[a] Confirmed by CMTR review safe end material used was type 304 with a carbon content of ≤ 0.025%.

Table 5.2-11

Main Steam Isolation Valves
Material Information

Item	Material Spec	Material Type	Minimum Design Wall Thickness
Body	SA-216	GR WCB	1.58 in.
Bonnet	SA-105	GR II	7.66 in.
Stem disc[a]	SA-105	N/A	1.56 in.
Disc piston[a]	SA-105	N/A	3.24 in.
Stem[a]	SA-564 or A-182	Tp 630 H1100 GR F6A C1 3	
Bonnet studs	SA-540	Class 4	1-5/8 in. diameter
Bonnet nuts	SA-194	GR 7	1-5/8 in. diameter

See Section 5.2.3.3 for fracture toughness response.

Piping connecting the MSIV
Outside diameter 12 in.
Nominal wall thickness = 1.103 in. plus 0.125 in.

[a] Redesign/replacement materials

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Table 5.2-12

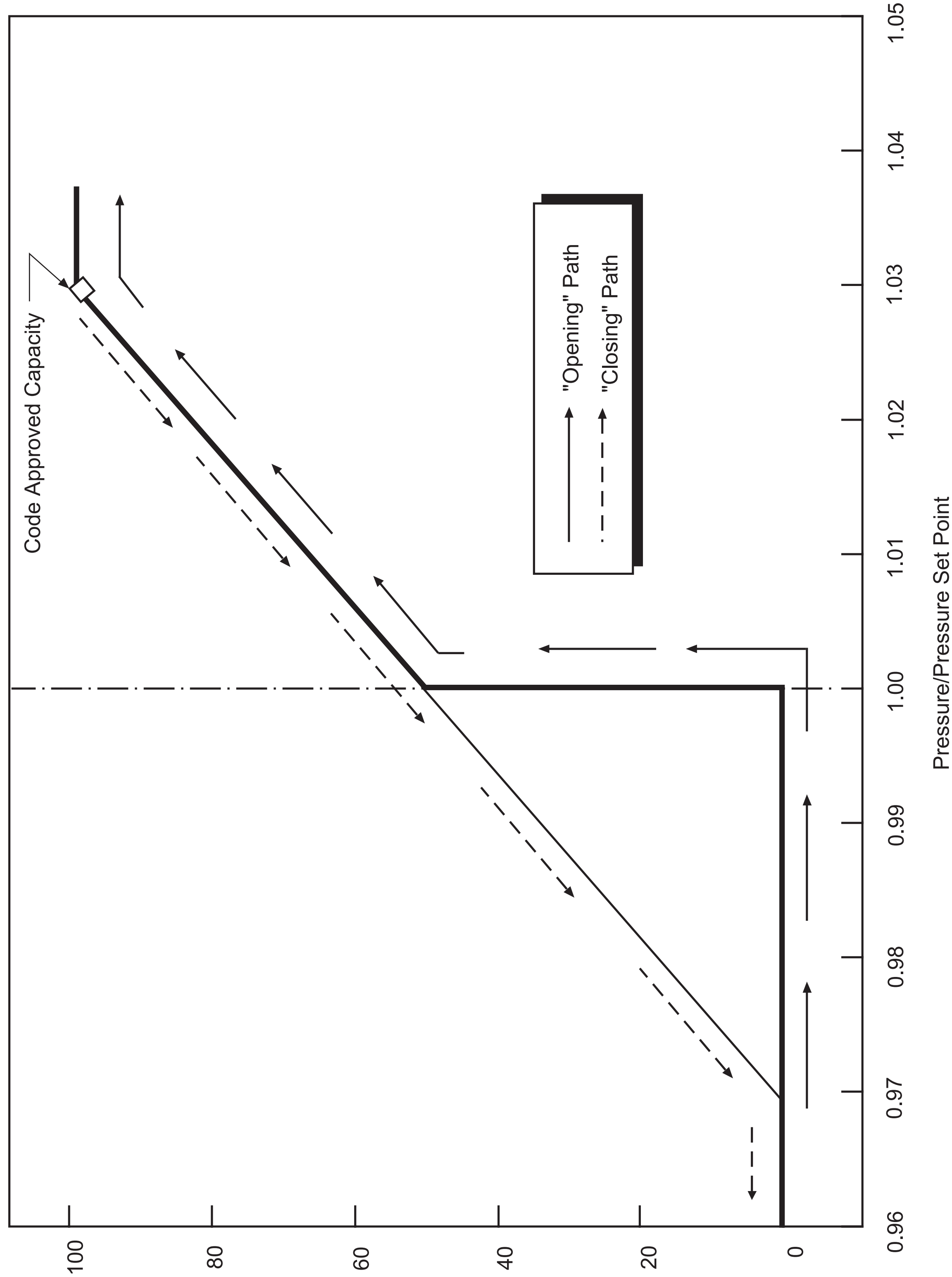
Summary of Isolation/Alarm of System Monitored and the Leak Detection Methods Used

		Variable Monitored												
FUNCTION		A	A	A	A/I	A/I	A	A/I	A/I	A/I	A/I	A/I	A	A
Source of Leakage	Location	High PC °F	PC Sump High Flow Rate	High/Dry-well Cooler Condensate Flow[a]	Equip-ment Area High T and ΔT	Low Steam Line Pressure	RB Sump or Drain High Flow Rate	PC Pressure (High)	High Flow Rate[b]	RCIC Diaphragm High Exhaust Line Pressure	RWCU ΔFlow (High)	Reactor Low Water Level	High Differential Pressure	Fission Products High[a]
Main steam line	PC	X	X	X		X[c]		X	X			X		X
	RB				X	X[c]	X		X			X		
RHR	PC	X	X	X				X				X		X
	RB				X		X		X			X		
RCIC steam	PC	X	X	X		X		X	X					X
	RB				X		X		X	X				
RCIC water	PC		X											
	RB						X							
RWCU water	PC	X	X	X				X[b]			X	X		X
	RB hot				X		X		X		X	X		
	RB cold						X		X		X	X		
Feedwater	PC	X	X	X				X						
	RB				X[d]		X							
ECCS water	PC		X										X	X
	RB						X						X	
Reactor coolant	PC	X	X	X				X				X		X
	RB													

PC - Primary containment
RB - Reactor building
RWCU - Reactor water cleanup
CCW - Closed cooling water

A - Alarm
I - Isolation

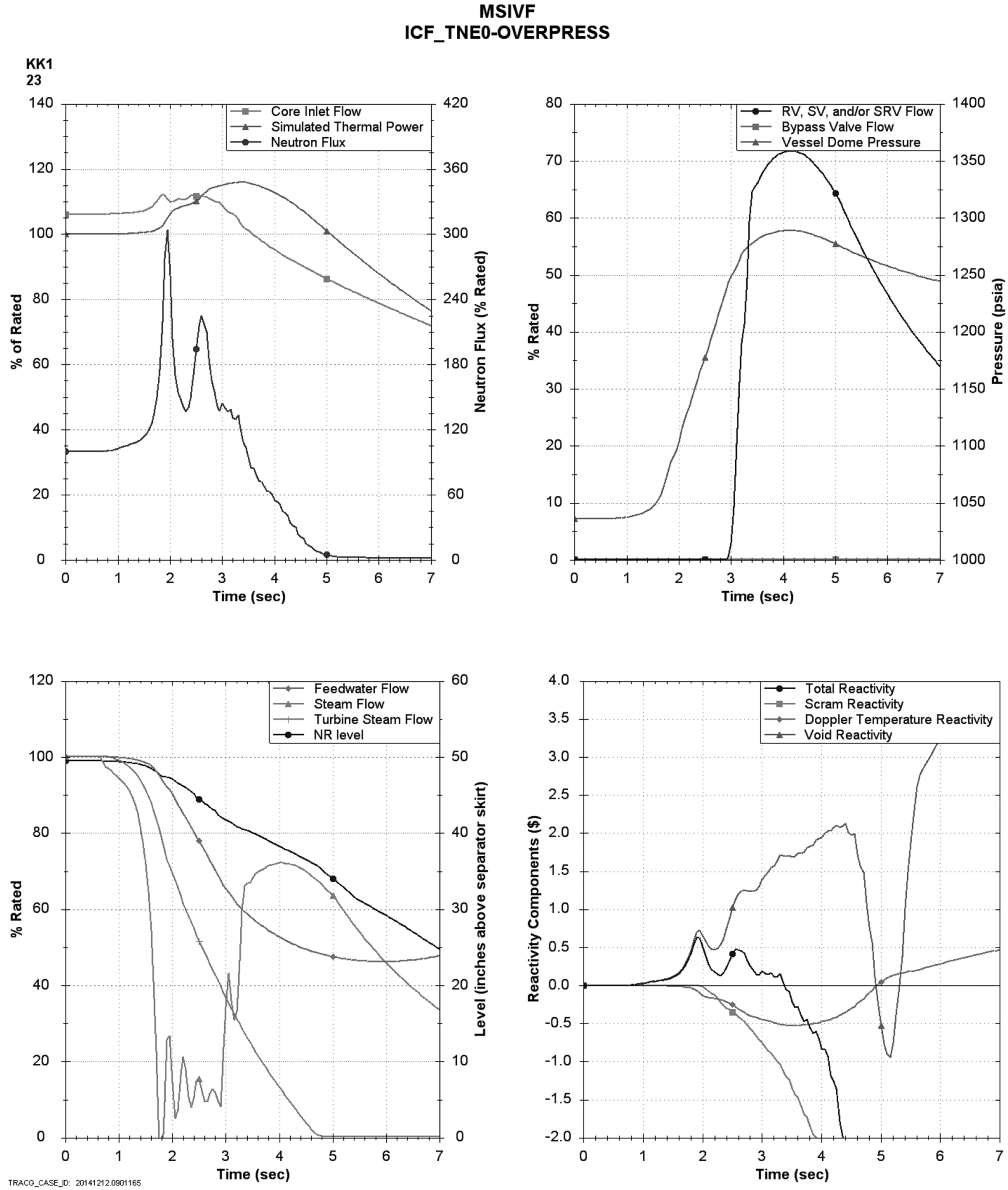
NOTE:
[a] All systems within the drywell share a common detection system.
[b] Break downstream of flow element will isolate the system.
[c] In run mode only.
[d] Alarm only (steam tunnel).



Columbia Generating Station
Final Safety Analysis Report

Simulated Safety Relief Valve Spring Mode Characteristic used for Capacity Sizing Analysis

Draw. No. 960690.46	Rev.	Figure 5.2-1



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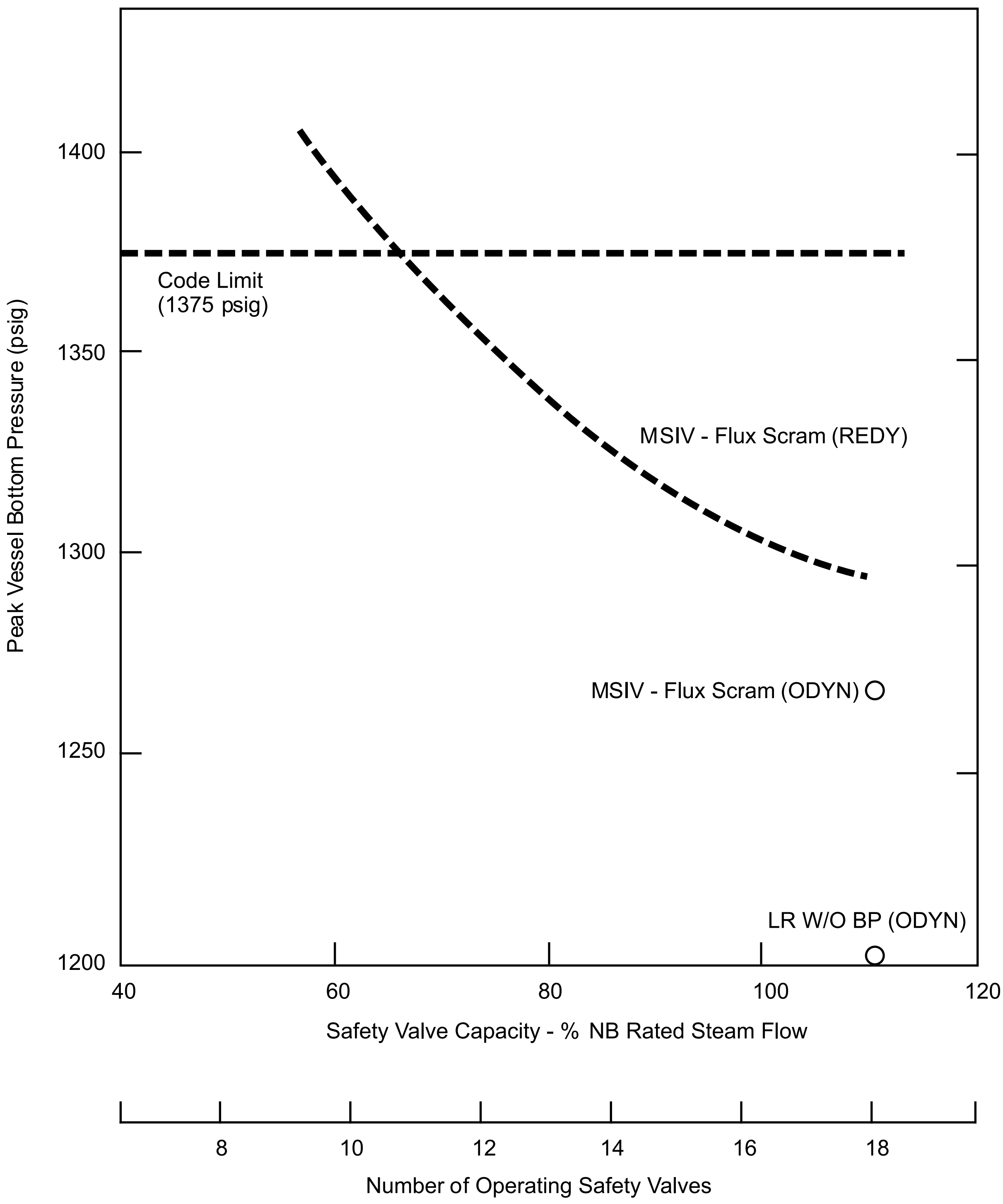
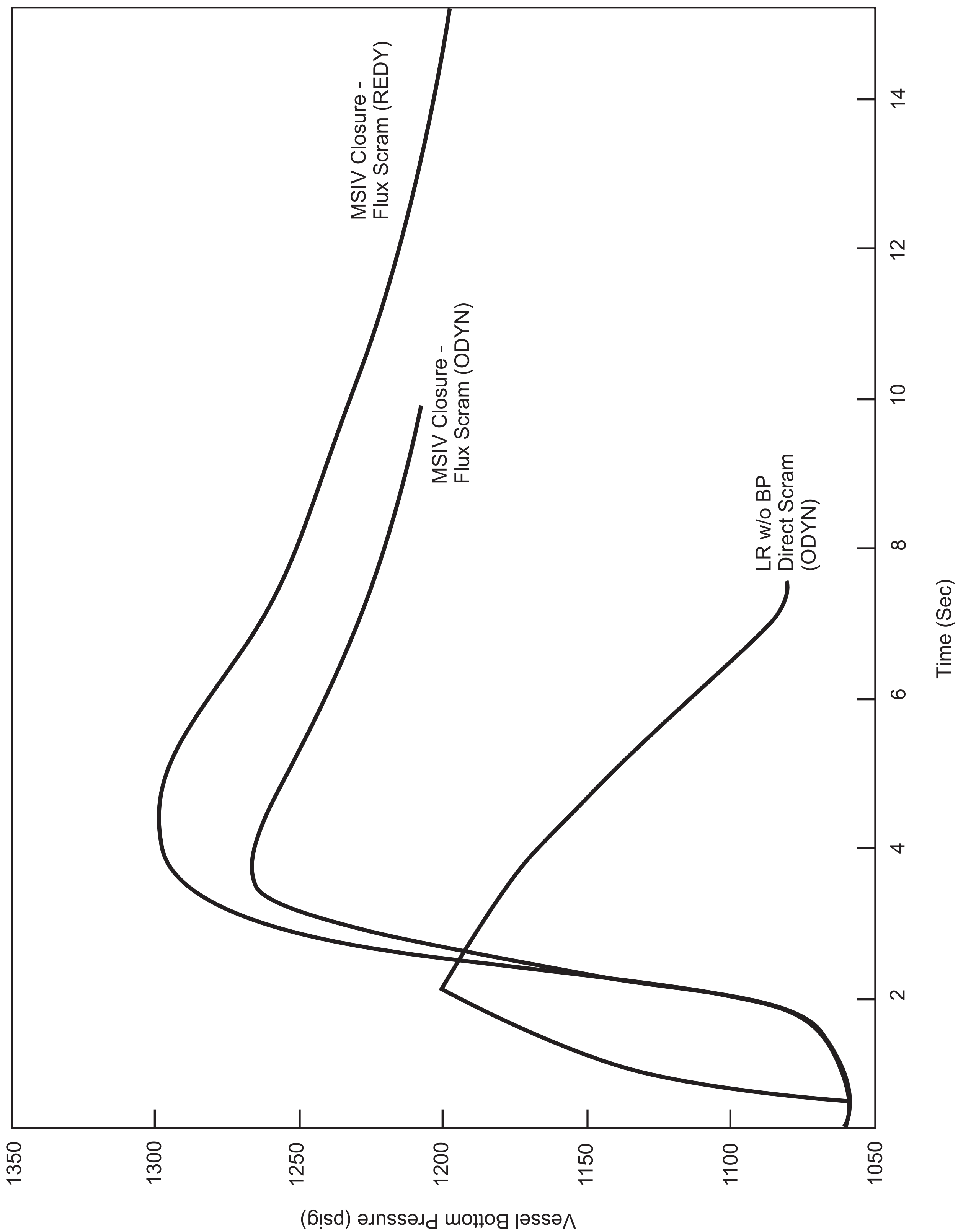
Draw. No. 950021.16	Rev. 1	Figure 5.2-2



Columbia Generating Station Final Safety Analysis Report	Peak Vessel Pressure Versus Safety Valve Capacity		
	Draw. No. 960690.47	Rev.	Figure 5.2-3



Columbia Generating Station **Final Safety Analysis Report**	**Time Response of Pressure Vessel for Pressurization Events**
	Draw. No. **960690.48** | Rev. | Figure **5.2-4**

TABLE VI: ELEVATION CORRELATION CHART

REFERENCE	(COLD VESSEL) INCHES ABOVE VESSEL ZERO	DESCRIPTION OF TRIPS	INSTRUMENT(S) PROVIDING TRIP	REACTOR VESSEL LEVEL IDENTITY SEE REF. 25 OF P&ID	CONTROL ROOM WATER LEVEL INDICATION AND TRIP LEVELS SEE NOTE 3: SAFEGUARDS – FUEL ZONE LR-R615 LI-R610	SAFEGUARDS – WIDE RANGE LR/PR-R623A,B LI-R604	SAFEGUARDS – NARROW RANGE C34 LR-R608	FEEDWATER – NARROW RANGE C34 LI-R606A,B,C	UPSET C34-LR-R608	SHUTDOWN LI-R605
TOP OF HEAD FLANGE	898 MAX								+180"	+400"
STEAM LINE NOZZLE N3	648									
INSTRUMENT LINE NOZZLE N14	599					+60"	+60"	+60"		
		TRIP RCIC & CLOSE HPCS INJECTION VALVE; CLOSE MAIN TURBINE STOP VALVES. TRIP FEED PUMPS.	TABLE IV REF. 2	8			+54.5"	+54.5"		
		HIGH LEVEL ALARM	REF. 2	7				+40.5"		
		NORMAL WATER LEVEL	REF. 2	5,6						
		LOW LEVEL ALARM	REF. 2	4				+31.5"		
		RUN RECIRC FLOW BACK *; SCRAM & CLOSE RHR SHUTDOWN COOLING ISOLATION VALVES. CONTRIBUTE TO AUTO DEPRESSURIZATION. RUN BACK RECIRC FLOW	TABLE IV REF. 2	3			+13"	+13"		
WATER LEVEL INSTRUMENT ZERO	527.5				0"	0"	0"	0"	0"	0"
BOTTOM OF DRYER SKIRT										
INSTRUMENT LINE NOZZLE N13	517	INITIATE RCIC & HPCS. CLOSE PRIMARY SYSTEMS ISOLATION VALVES EXCEPT RHR SHUTDOWN COOLING. MSIVs, MAIN STEAM LINE DRAIN VALVES, TRIP RECIRC PUMPS	TABLE IV	2	-110"	-50"				
		INITIATE RHR & CORE SPRAY SYS CONTRIBUTE TO AUTO DEPRESSURIZATION. START STAND-BY DIESEL. CLOSE MSIVs, MAIN STEAM LINE DRAIN VALVES.	TABLE IV	1		-129" / -150"				
INSTRUMENT LINE NOZZLE N12	366									
TOP OF ACTIVE FUEL	366.3									
JET PUMP INSTRUMENT NOZZLE N9	152.0				-310"					
JET PUMP DIFFUSER TAP	143.5									

* FUNCTION IS IN FEEDWATER CONTROL SYS(REF 2) FOR LOSS OF ONE FEED PUMP

TABLE I: SAFETY/RELIEF VALVE LOCATION, SUFFIX ASSIGNMENT, ASSOCIATED EQUIPMENT

SAFETY / RELIEF VALVE	F013	A	B	C	D	E	F	G	H	J	K	L	M *	N ⊛	P	R *	S *	U ⊛	V ⊛
ACCUMULATORS	A003 (ADS)												M	N	P	R	S	U	V
	A004	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
CHECK VALVES	F036	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
	F040(ADS)												M	N	P	R	S	U	V
VACUUM BREAKER	F037	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
PRESSURE SWITCH	N039	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
COMPUTER INPUTS FOR VALVE POS(REF 3) C		C1732	C1733	C1734	C1735	C1736	C1737	C1738	C1739	C1740	C1741	C1742	C1743	C1744	C1745	C1746	C1747	C1748	C1749
TEMPERATURE ELEMENT	N004	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	U	V
ADS FUNCTION													YES	YES	YES	YES	YES	YES	YES

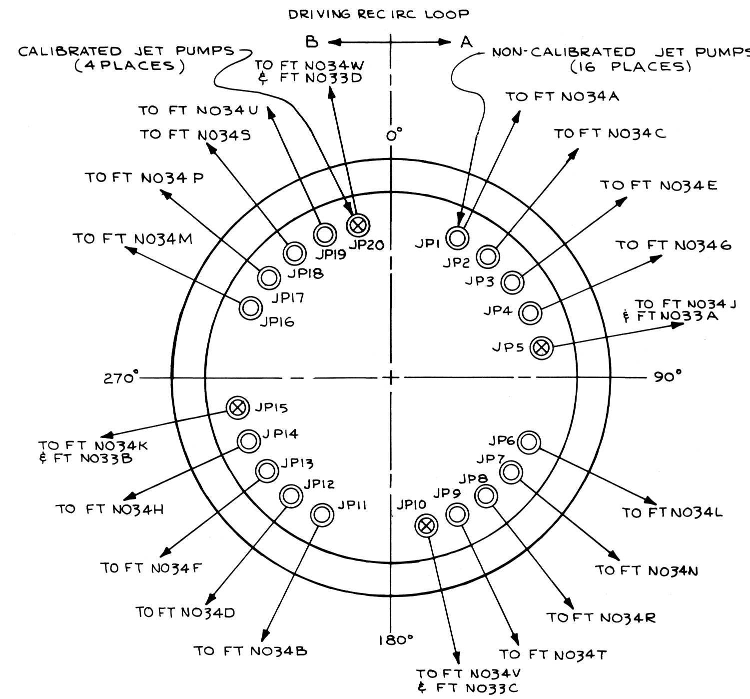
ADS - SAFETY/RELIEF VALVE FOR AUTO DEPRESSURIZATION
* - CONTROL PROVIDED IN REMOTE SHUTDOWN SYS (REF 5)
⊛ - CONTROL PROVIDED IN ALTERNATE REMOTE SHUTDOWN SYS (SEE REF 5)
⊛⊛ NS4 EXCEPT MSIVs, MAIN STEAM LINE DRAIN VALVES.
⊛⊛⊛ MSIVs, MAIN STEAM LINE DRAIN VALVES.

TABLE IV: WATER LEVEL INSTRUMENT CONTACT UTILIZATION

INSTRUMENT NUMBER	DIV	UPPER RANGE TRIP 2-A	UPPER RANGE TRIP 2-B	LEVEL #	LOWER RANGE TRIP 1-A	LOWER RANGE TRIP 1-B	LEVEL #	TRANS E/S MPL #
LIS-N024A	IA				RPS (NS4)		3	—
LIS-N024B	IB	RCIC (I)			RPS (NS4)		3	—
LIS-N024C	IIA				RPS (NS4)		3	—
LIS-N024D	IIB	RCIC (II)			RPS (NS4)		3	—
LIS-N100A	III	HPCS		8				—
LIS-N100B	III	HPCS		8				
LIS-N038A	I					ADS (A)	3	—
LIS-N038B	II					ADS (B)	3	—
LIS-N037A	I	RCIC		2	LPCS & RHR(A)	ADS (A)	1	—
LIS-N037B	II	RCIC		2	RHR(B) & RHR(C)	ADS(B)	1	—
LIS-N037C	I	RCIC		2	LPCS & RHR(A)	ADS(A)	1	—
LIS-N037D	II	RCIC		2	RHR(B) & RHR(C)	ADS(B)	1	—
LIS-N031A	III	HPCS		2				—
LIS-N031B	III	HPCS		2				—
LIS-N031C	III	HPCS		2				—
LIS-N031D	III	HPCS		2				—
MS-LS-300A	IA	⊛⊛		2				C72A-K613A
MS-LS-300B	IB	⊛⊛		2				C72A-K613B
MS-LS-300C	IIA	⊛⊛		2				C72A-K613C
MS-LS-300D	IIB	⊛⊛		2				C72A-K613D
LIS-N036A		RECIRC (A)		2				—
LIS-N036B		RECIRC (B)		2				—
LIS-N036C		RECIRC (A)		2				—
LIS-N036D		RECIRC(B)		2				—
								E12 K603A
MS-LIS-200A	IA	⊛⊛⊛		1				C72A-K613A
MS-LIS-200B	IB	⊛⊛⊛		1				C72A-K613B
MS-LIS-200C	IIA	⊛⊛⊛		1				C72A-K613C
MS-LIS-200D	IIB	⊛⊛⊛		1				C72A-K613D

TABLE V: PRESSURE INSTRUMENT CONTACT UTILIZATION

INSTRUMENT NUMBER	DIV	TRIP	TRANS E/S MPL #
PS N020A	IA	RPS	—
PS N020B	IB	RPS	—
PS N020C	IIA	RPS	—
PS N020D	IIB	RPS	—
PS N023A	IA	RPS	—
PS N023B	IB	RPS	—
PS N023C	IIA	RPS	—
PS N023D	IIB	RPS	—
PS N039 *	I	RELIEF VALVE	—
PS N045A		RECIRC (A)	—
PS N045B		RECIRC (B)	—
PS N045C		RECIRC (A)	—
PS N045D		RECIRC (B)	—
PS N047A,C	III	HPCS	—
PS N047B,D	III	HPCS	—
PS N048A,C	I	LPCS RHR(A)	—
PS N048B,D	II	RHR(B), RHR(C)	—
PT N051A	IA	—	K613A
PT N051B	IB	—	K613B
PS N015A	IA	NS4	—
PS N015B	IB	NS4	—
PS N015C	IIA	NS4	—
PS N015D	IIB	NS4	—
VS N056A	IA	NS4	—
VS N056B	IB	NS4	—
VS N056C	IIA	NS4	—
VS N056D	IIB	NS4	—
LT N027	—	—	K615
dPT N032	—	—	K615
LT-N027	—	—	K615
dPT-N032	—	—	K615
PT-N018	—	SRV TEST	—
PS-N413A,C	I	RHR(A), LPCS	—
PS-N413B,D	II	RHR(B) & (C)	—



PLAN X

MPL NO. B22-1040

NOTES:

1. REF. DOC. 1 SHALL BE USED WITH AND FORM PART OF THIS P&ID DATA, IF THERE ARE ANY CONFLICTS BETWEEN THE P&ID AND THIS P&ID DATA, THE P&ID DATA SHALL GOVERN.
2. MPL NO'S ARE PREFIXED BY B22 UNLESS OTHERWISE NOTED.
3. WATER LEVEL INSTRUMENTS FOR VARIOUS RANGES ARE CALIBRATED AS STATED BELOW. ALL WATER LEVEL SWITCH SET POINTS ARE NOMINAL: IE; THE ANALYSES ARE PERFORMED WITH THE SWITCH TRIP UNCERTAINTY INCLUDED. REACTOR BUILDING TEMPERATURE ASSUMED TO BE 75°F.
   - A. FUEL ZONE: THE INSTRUMENTS ARE CALIBRATED FOR SATURATED WATER STEAM CONDITIONS AT 0 PSIG IN THE VESSEL AND THE DRYWELL WITH NO JET PUMP FLOW. WATER LEVEL SWITCH TRIP UNCERTAINTY IS ± 6" OF WATER LEVEL AT CALIBRATION CONDITIONS.
   - B. WIDE RANGE: THE INSTRUMENTS ARE CALIBRATED FOR 1000 PSIG IN THE VESSEL, 135°F IN THE DRYWELL AND 20 BTU/LB SUBCOOLING BELOW THE MIDDLE WATER LEVEL NOZZLE AND SATURATED CONDITIONS ABOVE THE MIDDLE WATER LEVEL NOZZLE WITH NO JET PUMP FLOW. WATER LEVEL SWITCH TRIP UNCERTAINTY IS ± 6" OF WATER LEVEL AT CALIBRATION CONDITIONS.
   - C. NARROW RANGE: (SAFEGUARDS AND FEEDWATER): THE INSTRUMENTS ARE CALIBRATED FOR SATURATED WATER STEAM CONDITIONS AT 1000 PSIG IN THE VESSEL AND 135°F IN THE DRYWELL. WATER LEVEL SWITCH TRIP UNCERTAINTY IS ± 1.5" OF WATER LEVEL AT CALIBRATION CONDITIONS.
   - D. UPSET RANGE: THE INSTRUMENT IS CALIBRATED FOR SATURATED WATER STEAM CONDITIONS AT 1000 PSIG IN THE VESSEL AND 135°F IN THE DRYWELL.
   - E. SHUTDOWN: THE INSTRUMENT IS CALIBRATED FOR 120°F WATER AT 0 PSIG IN VESSEL AND 80°F IN THE DRYWELL.

76/E 445

REFERENCE DOCUMENTS:

1. NUCLEAR BOILER SYSTEM P&ID------------------------B22-1010
2. FEEDWATER CONTROL SYSTEM IED----------------------C34-1010
3. NUCLEAR BOILER SYSTEM FCD-------------------------B22-1030
4. ELEC EQ SEP SAFEGUARD SYS-------------------------A62-4050
5. REMOTE SHUTDOWN SYS IED---------------------------C61-1010

TABLE II: JET PUMP INSTRUMENTATION SUFFIX LETTER ASSIGNMENT

LOOP	A										B									
JP NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FT N034 E/SK615	A	C	E	G	J	L	N	R	T	V	B	D	F	H	K	M	P	S	U	W
dPI R608	A	C	E	G	J	L	N	R	T	V	B	D	F	H	K	M	P	S	U	W
√ K600	A	C	E	G	J	L	N	R	T	V	B	D	F	H	K	M	P	S	U	W
Σ	K601A				K601C				K607A		K601B				K601D				K607B	
Σ	K602A										K602B									
C	A1751	A1752	A1753	A1754	A1755	A1756	A1757	A1758	A1759	A1760	A1761	A1762	A1763	A1764	A1765	A1766	A1767	A1768	A1769	A1770
FT N033	—	—	—	—	A	—	—	—	—	C	—	—	—	—	B	—	—	—	—	D
√ K605	—	—	—	—	A	—	—	—	—	C	—	—	—	—	B	—	—	—	—	D
FI R609	—	—	—	—	A	—	—	—	—	C	—	—	—	—	B	—	—	—	—	D

THE SUPPLY SYSTEM IS RESPONSIBLE FOR DESIGN CHANGE CONTROL OF THIS DOCUMENT

FSAR FIG.

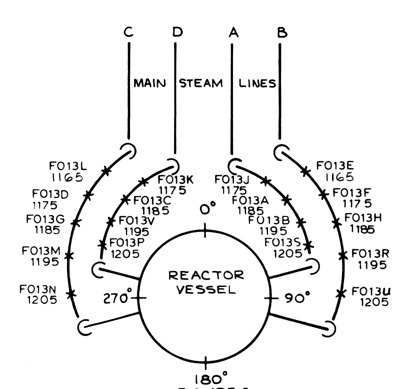


FIGURE I
SAFETY/RELIEF VALVE LOCATION & SPRING SET PRESSURE

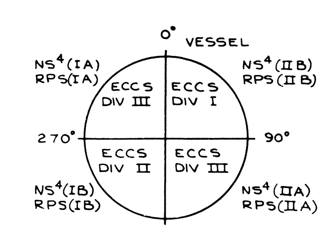
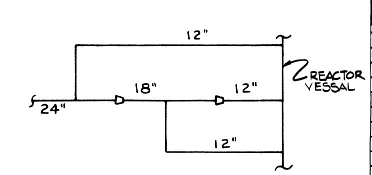


FIGURE II
DIVISION ORIENTATION FOR VESSEL INSTRUMENTATION (SEE REF 4)

02-02B22-04	26	22	1
CVI NO	CVI SHT	REV	DWG SHT



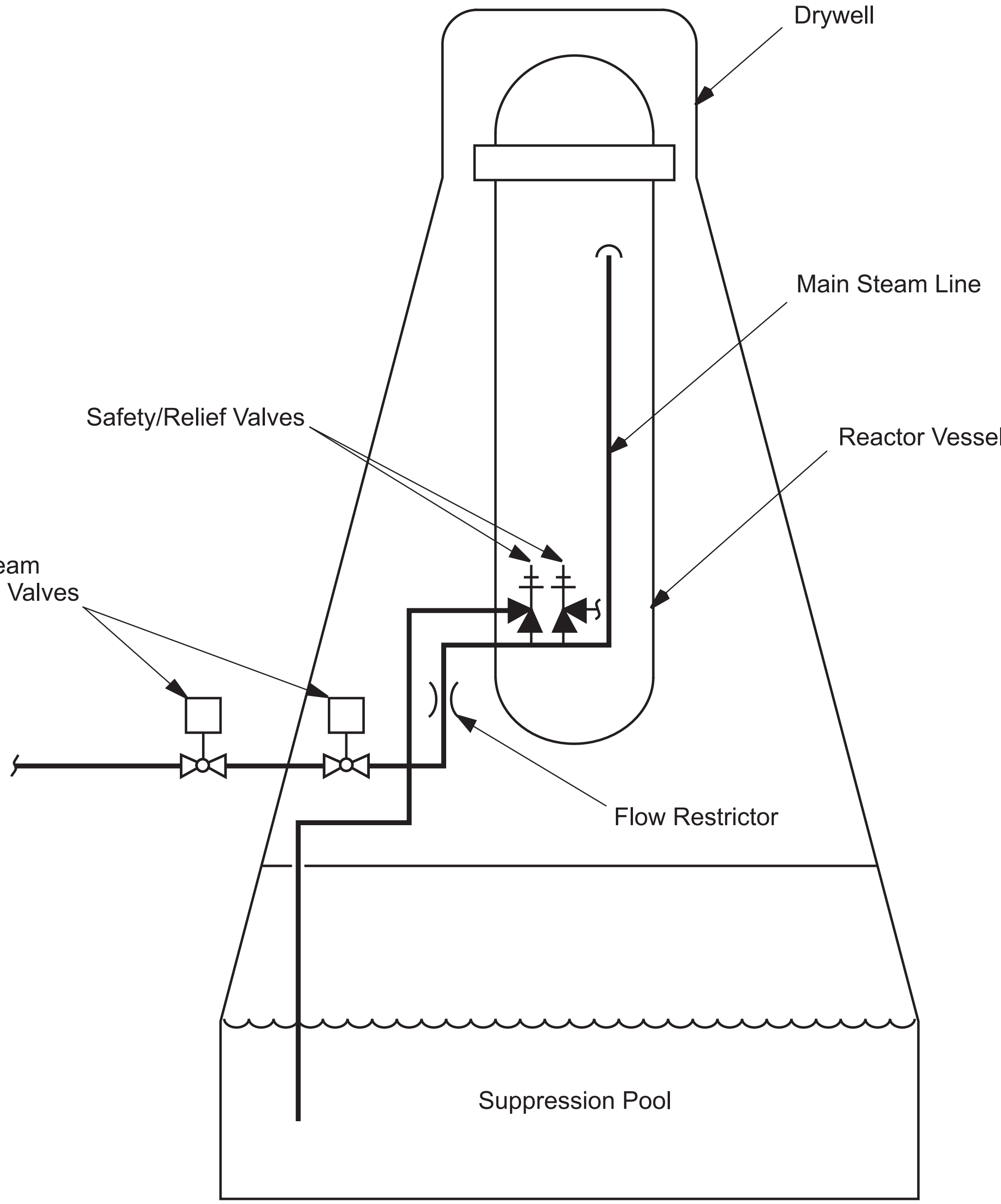
FEEDWATER PIPING DETAIL
(TYPICAL)

Columbia Generating Station
Final Safety Analysis Report

Nuclear Boiler System - P&ID

Draw. No. 02B22-04,26,1 | Rev. 22 | Figure 5.2-5

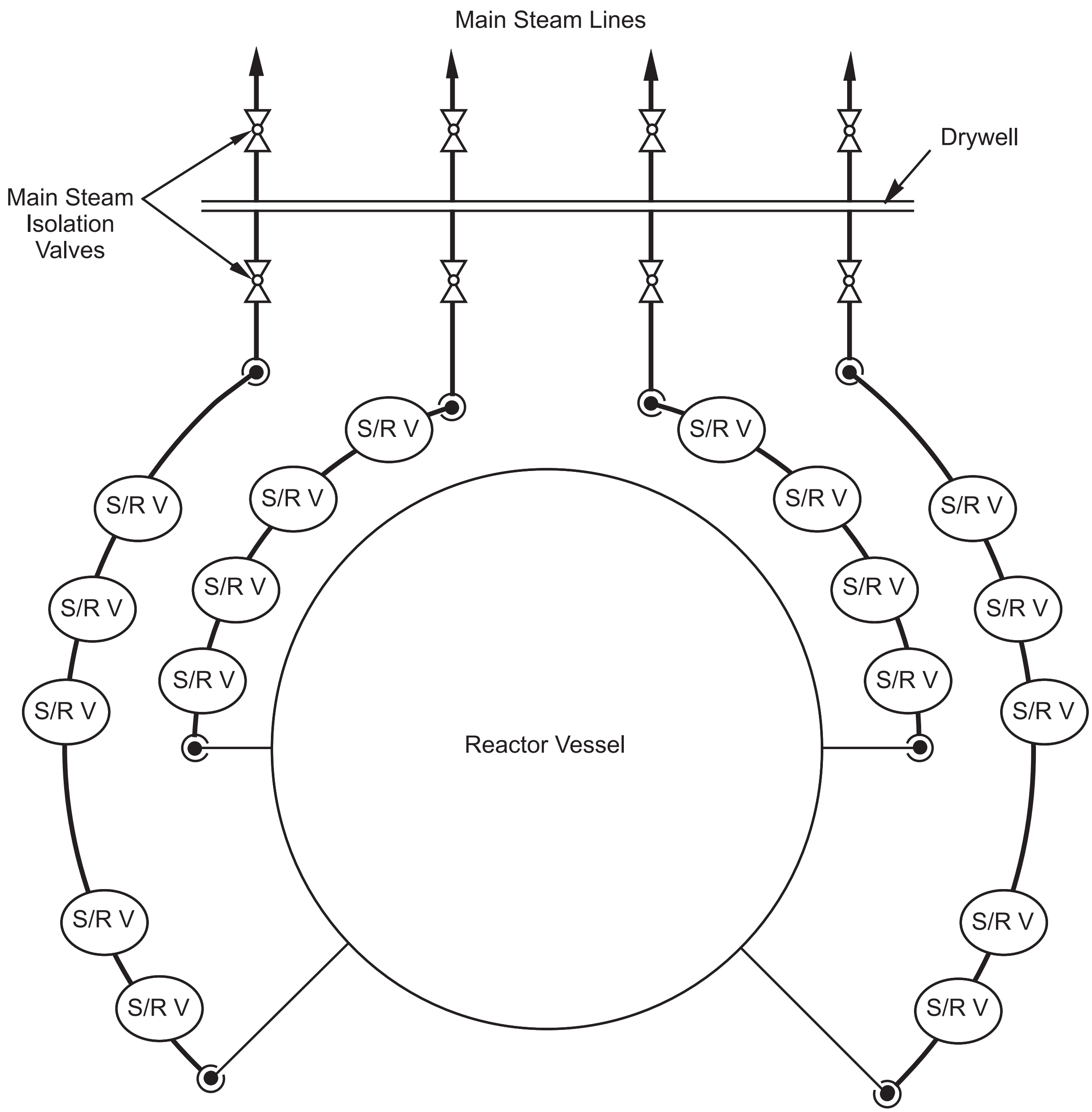
Form No. 960690ai



Columbia Generating Station
Final Safety Analysis Report

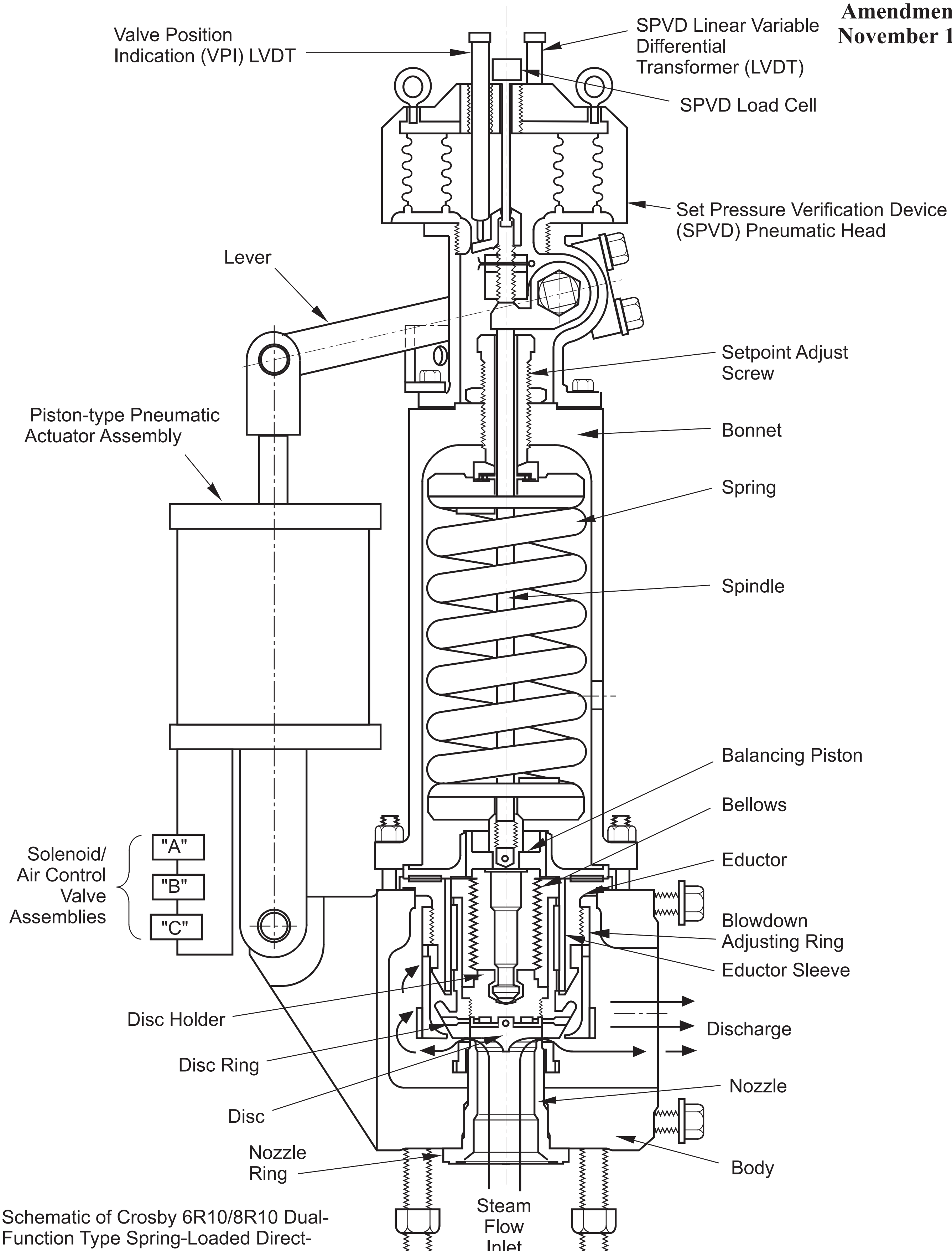
Safety/Relief Valve Schematic Elevation

Draw. No. 960690.49	Rev.	Figure 5.2-6



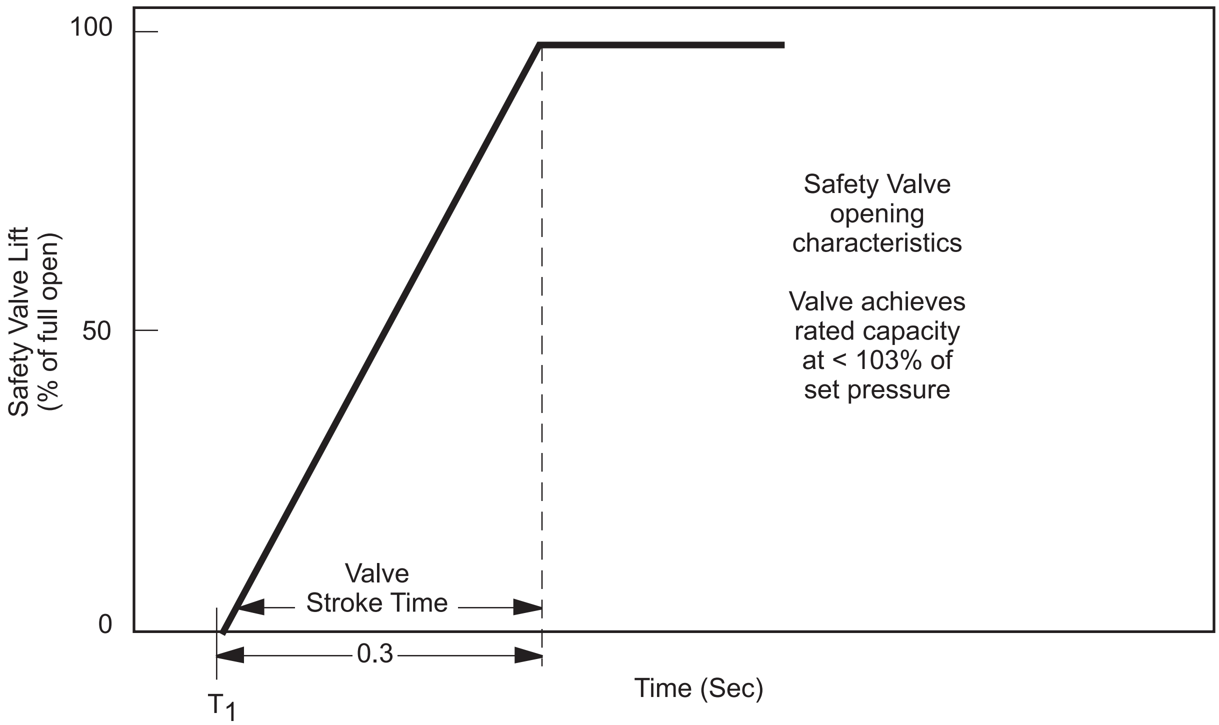
Safety/Relief Valve and
Steam Line Schematic

Draw. No. 960690.62	Rev.	Figure 5.2-7



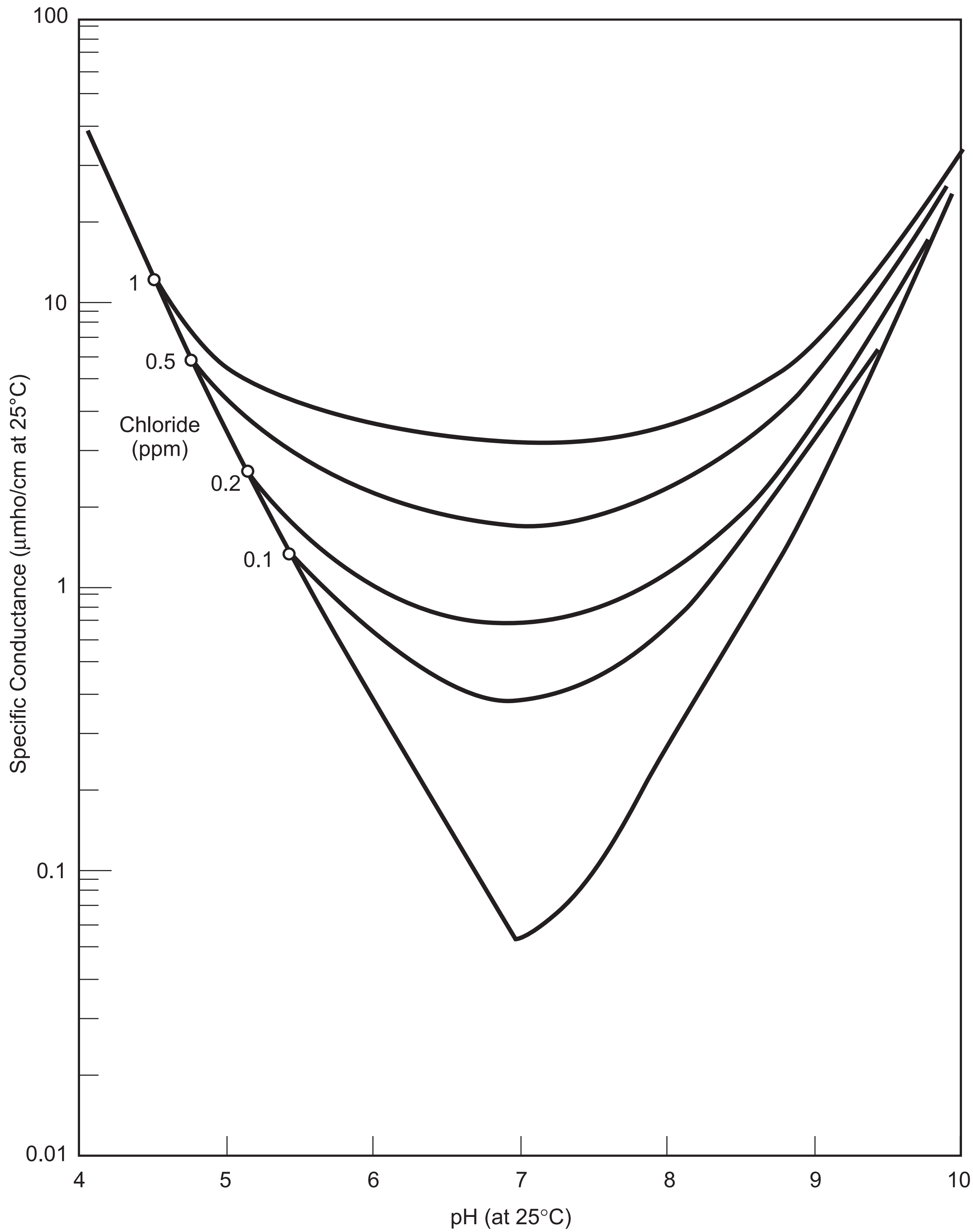
Schematic of Crosby 6R10/8R10 Dual-Function Type Spring-Loaded Direct-Acting Safety/Relief Valve

Columbia Generating Station Final Safety Analysis Report	Schematic of Safety Valve with Auxiliary Actuating Device
	Draw. No. 960690.85 | Rev. | Figure 5.2-8



T_1 = Time at which pressure exceeds the valve set pressure

Safety Valve Lift Versus Time Characteristics



Conductance Versus pH as a Function of Chloride Concentration of Aqueous Solution at 25°C

Draw. No. 960690.51 | Rev. | Figure 5.2-10

DELETED

5.3 REACTOR VESSEL

5.3.1 REACTOR VESSEL MATERIALS

5.3.1.1 Materials Specifications

The materials used in the reactor pressure vessel and appurtenances are shown in Table 5.2-7 together with the applicable specifications.

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

The reactor pressure vessel is primarily constructed from low alloy, high strength steel plate and forgings. Plates are ordered to ASME SA-533, Grade B, Class 1, and forgings to ASME SA-508, Class 2. These materials are melted to fine grain practice and are supplied in the quenched and tempered condition. Further restrictions include a requirement for vacuum degassing to lower the hydrogen level and improve the cleanliness of the low alloy steels.

Studs, nuts, and washers for the main closure flange are ordered to ASME SA-540, Grade B23 or Grade B24. Welding electrodes are low hydrogen type ordered to ASME SFA 5.5.

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

All fabrication of the reactor pressure vessel is performed in accordance with the General Electric Company (GE) approved drawings, fabrication procedures, and test procedures. The shells and vessel heads are made from formed plates and the flanges and nozzles from forgings. Welding performed to join these vessel components is in accordance with procedures qualified per ASME Section III and IX requirements. Weld test samples are required for each procedure for major vessel full penetration welds. Tensile and impact tests are performed to determine the properties of the base metal, heat-affected zone (HAZ) and weld metal. Submerged arc and manual stick electrode welding processes are employed. Electroslag welding is not permitted. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the requirements of ASME Section III, Subsection NB. Postweld heat treatment at 1100°F minimum is applied to all low alloy steel welds.

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

The materials, fabrication procedures, and testing methods used in the construction of boiler water reactor (BWR) reactor pressure vessels meet or exceed requirements of ASME Section III, Class 1 vessels.

5.3.1.3 Special Methods for Nondestructive Examination

The materials and welds on the reactor pressure vessel were examined in accordance with methods prescribed and met the acceptance requirements specified by ASME Boiler and Pressure Vessel (B&PV) Code Section III. In addition, the pressure retaining welds were ultrasonically examined using manual techniques. The ultrasonic examination method, including calibration, instrumentation, scanning sensitivity, and coverage was based on the requirements imposed by ASME Code Section XI in Appendix I. Acceptance standards were equivalent or more restrictive than required by ASME Code Section XI.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

The degree of compliance with Regulatory Guides 1.31, 1.34, 1.43, 1.44, 1.50, 1.71, and 1.99 is described in Section 1.8.

5.3.1.5 Fracture Toughness

5.3.1.5.1 Compliance with Code Requirements

The ferritic pressure boundary material of the reactor pressure vessels was qualified by impact testing in accordance with the 1971 edition of Section III ASME Code and Summer 1971 Addenda. From an operational standpoint, the minimum temperature limits for pressurization defined by the 1998 Edition of Section XI ASME Code and 2000 Addenda, Appendix G, Protection Against Nonductile Failure, are used as the basis for compliance with ASME Code Section III.

5.3.1.5.2 Compliance with 10 CFR 50 Appendix G

A major condition necessary for full compliance to Appendix G was satisfaction of the requirements of the Summer 1972 Addenda to Section III. This was not possible with components which were purchased to earlier Code requirements. For the extent of the compliance, see Table 5.3-1.

Ferritic material complying with 10 CFR 50 Appendix G must have both drop-weight tests and Charpy V-notch (CVN) tests with the CVN specimens oriented transverse to the maximum material working direction to establish the RT_{NDT}. The CVN tests must be evaluated against both an absorbed energy and a lateral expansion criteria. The maximum acceptable RT_{NDT} must be determined in accordance with the analytical procedures of ASME Code Section III, Appendix G. Appendix G of 10 CFR 50 requires a minimum of 75 ft-lb upper shelf CVN

energy for beltline material. It also requires at least 45 ft-lb CVN energy and 25 mils lateral expansion for bolting material at the lower of the preload or lowest service temperature.

By comparison, material for the Columbia Generating Station (CGS) reactor vessels was qualified by either drop-weight tests or longitudinally oriented CVN tests (both not required), confirming that the material nil-ductility transition temperature (NDTT) is at least 60°F below the lowest service temperature. When the CVN test was applied, a 30 ft-lb energy level was used in defining the NDTT. There was no upper shelf CVN energy requirement on the beltline material. The bolting material was qualified to a 30 ft-lb CVN energy requirement at 60°F below the minimum preload temperature.

From the previous comparison it can be seen that the fracture toughness testing performed on the CGS reactor vessel material cannot be shown to comply with 10 CFR 50 Appendix G. However, to determine operating limits in accordance with 10 CFR 50 Appendix G, estimates of the beltline material RT_{NDT} and the highest RT_{NDT} of all other material were made and are discussed in Section 5.3.1.5.2.2. The method for developing these operating limits is also described therein.

On the basis of the last paragraph on page 19013 of the July 17, 1973, Federal Register, the following is considered an appropriate method of compliance.

5.3.1.5.2.1 Intent of Proposed Approach. The intent of the proposed special method of compliance with 10 CFR 50 Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits ensure that a margin of safety against a nonductile failure of this vessel is very nearly the same as that for a vessel built to the Summer 1972 Addenda.

The specific temperature limits for operation when the core is critical are based on 10 CFR 50 Appendix G, Paragraph IV, A.2.C.

5.3.1.5.2.2 Operating Limits Based on Fracture Toughness. Operating limits which define minimum reactor vessel metal temperatures versus reactor pressure during normal heatup and cooldown and during inservice hydrostatic testing were established using the methods of Appendix G of Section XI of the ASME B&PV Code, 1998 Edition, 2000 Addenda. The results are shown in Figure 5.3-1.

All the vessel shell and head areas remote from discontinuities plus the feedwater nozzles were evaluated, and the operating limit curves are based on the limiting location. The boltup limits for the flange and adjacent shell region are based on a minimum metal temperature of RT_{NDT} +60°F. The maximum through-wall temperature gradient from continuous heating or cooling at 100°F/hr was considered. The safety factors applied were as specified in ASME Section XI Appendix G.

For the purpose of setting these operating limits the reference temperature, RT_{NDT}, is determined from the toughness test data taken in accordance with requirements of the code to which this vessel is designed and manufactured. This toughness test data, CVN and/or dropweight NDT, is analyzed to permit compliance with the intent of 10 CFR 50 Appendix G. Because all toughness testing needed for strict compliance with Appendix G was not required at the time of vessel procurement some toughness results are not available. For example, longitudinal CVNs, instead of transverse, were tested, usually at a single test temperature of +10°F or -20°F, for absorbed energy. Also, at the time either CVN or NDT testing was permitted; therefore, in many cases both tests were not performed as is currently required. To substitute for this absence of certain data, toughness property correlations were derived for the vessel materials to operate on the available data to give a conservative estimate of RT_{NDT} compliant with the intent of Appendix G criteria.

These toughness correlations vary, depending upon the specific material analyzed, and were derived from the results of Welding Research Council (WRC) Bulletin 217, "Properties of Heavy Section Nuclear Reactor Steels," and from toughness data from the CGS vessel and other reactors. In the case of vessel plate material (SA-533 Grade 8, Class 1), the predicted limiting toughness property is either NDT or transverse CVN 50 ft-lb temperature minus 60°F. NDT values are available for CGS vessel shell plates. The transverse CVN 50 ft-lb transition temperature is estimated from longitudinal CVN data in the following manner. The lowest longitudinal CVN 50 ft-lb value is adjusted to derive a longitudinal CVN 50 ft-lb transition temperature by adding 2°F per ft-lb to the test temperature. If the actual data equals or exceeds 50 ft-lb, the test temperature is used. Once the longitudinal 50 ft-lb temperature is derived, an additional 30°F is added to account for orientation effects and to estimate the transverse CVN 50 ft-lb temperature minus 60°F, estimated in the preceding manner.

Using the above general approach, an initial RT_{NDT} of 28°F was established for the core beltline region.

For forgings (SA-508 Class 2), the predicted limiting property is the same as for vessel plates. CVN and NDT values are available for the vessel flange, closure head flange, and feedwater nozzle materials for CGS. RT_{NDT} is estimated in the same way as for vessel plate.

For the vessel weld metal the predicted limiting property is the CVN 50 ft-lb transition temperature minus 60°F, as the NDT values are -50°F or lower for these materials. This temperature is derived in the same way as for the vessel plate material, except the 30°F addition of orientation effects is omitted since there is no principal working direction. When NDT values are available, they are also considered and the RT_{NDT} is taken as the higher of NDT or the 50 ft-lb temperature minus 60°F. When NDT is not available, the RT_{NDT} shall not be less than -50°F, since lower values are not supported by the correlation data.

For vessel weld HAZ material the RT_{NDT} is assumed the same as for the base material as ASME Code weld procedure qualification test requirements, and postweld heat treatment indicates this assumption is valid.

Figure 5.3-2 provides a sketch of the reactor vessel, including the basic dimensions, all longitudinal and circumferential welds, and all plates of the beltline region. Tables 5.3-2 through 5.3-7 contain the supporting information for Figure 5.3-2, such as piece mark, heat number, and impact data for the plates and filler material used in the beltline region.

Closure bolting material (SA-540 Grade B24) toughness test requirements for CGS were for 30 ft-lb at 60°F below the boltup temperature. Current code requirements are for 45 ft-lb and 25 mils lateral expansion at the preload or lowest service temperature, including boltup. All CGS closure stud materials meet current requirements at +10°F.

The effect of the main closure flange discontinuity was considered by adding 60°F to the RT_{NDT} to establish the minimum temperature for boltup and pressurization. The minimum boltup temperature of 80°F for CGS, which is shown on Figure 5.3-1, is based on an initial RT_{NDT} of +20°F for the shell plate connecting to the closure flange forgings.

The effect of the feedwater nozzle discontinuities were considered by adjusting the results of a BWR/6 reactor discontinuity analysis to the reactor. The adjustment was made by increasing the minimum temperatures required by the difference between the CGS and BWR/6 feedwater nozzle forging RT_{NDT}. The feedwater nozzle adjustment was based on an RT_{NDT} of 0°F.

The reactor vessel closure studs have a minimum Charpy impact energy of 45 ft-lb and 26 mils lateral expansion at 10°F. The lowest service temperature for the closure studs is 10°F.

Vessel irradiation embrittlement of beltline materials, as measured by adjusted reference temperatures and upper shelf energies due to increased flux, was evaluated against the requirements of 10 CFR 50 Appendix G. For a predicted fluence of 7.41 x 10^{17}n/cm^2, fracture toughness values are acceptable and remain within Appendix G limits.

5.3.1.5.2.3 Temperature Limits for Boltup. A minimum temperature of 10°F is required for the closure studs. A sufficient number of studs may be tensioned at 70°F to seal the closure flange O-rings for the purpose of raising reactor water level above the closure flanges to assist in warming them. The flanges and adjacent shell are required to be warmed to a minimum temperature of 80°F before they are stressed by the full intended bolt preload. The fully preloaded boltup limits are shown in Figure 5.3-1.

5.3.1.5.2.4 Inservice Inspection Hydrostatic or Leak Pressure Tests. Based on 10 CFR 50 Appendix G, and Regulatory Guide 1.99, Revision 2, requirements, pressure/temperature limit curves were established based on an RT_{NDT} of 28°F for the limiting beltline material; see Figure 5.3-1. The fracture toughness analysis for inservice inspection of leak test resulted in

curve A shown in Figure 5.3-1. The predicted shift in the RT_{NDT} temperature was determined using the methodology outlined in Regulatory Guide 1.99, Revision 2.

Technical Specification 3.10.1 allows inservice leak and hydrostatic testing to be performed in Mode 4 when the metallurgical characteristics of the reactor pressure vessel require testing at temperatures greater than 200°F, given specified Mode 3 Limiting Conditions for Operations are met. This exemption is only applicable provided reactor coolant temperature does not exceed 275°F.

5.3.1.5.2.5 Operating Limits During Heatup, Cooldown, and Core Operation. The fracture toughness analysis was done for the normal heatup or cooldown rate of 100°F/hr. The temperature gradients and thermal stress effects corresponding to this rate were included. The results of the analysis are operating limits defined by Figure 5.3-1. Curves A, B, and C give the limits for hydrotest, nonnuclear heating, and nuclear heating. The minimum boltup temperature of 80°F is based on an RT_{NDT} at 20°F for a shell plate which connects to the lower flange (Heat and Slab No. C-1307-2); above 80°F the core beltline plate (Heat and Slab No. C-1272-1), which has an initial RT_{NDT} of 28°F, is most limiting for inservice hydrostatic or leak pressure tests (curve A). The feedwater nozzles, which have an RT_{NDT} of 0°F, are more restrictive than the core beltline at lower pressures during nonnuclear and nuclear heating (curves B and C).

5.3.1.5.2.6 Reactor Vessel Annealing. Inplace annealing of the reactor vessel to counteract radiation embrittlement is unnecessary because beltline material adjusted reference temperature of the NDT is well within the 10 CFR 50 Appendix G 200°F screening limit.

5.3.1.6 Material Surveillance

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

The CGS plant-specific RPV materials surveillance program is replaced by the NRC approved BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP), as described in the latest approved revision of BWRVIP-86 (Reference 5.3.4-2). The ISP meets the requirements of 10 CFR 50, Appendix H.

The current surveillance capsule withdrawal schedule for the representative materials for the CGS vessel is based on the latest approved revision of BWRVIP-86 (Reference 5.3.4-2). No capsules from the CGS vessel are included in the ISP. The withdrawal of capsules for the CGS plant-specific surveillance program is permanently deferred by participation in the ISP. Capsules from other plants will be removed and tested in accordance with the ISP

implementation plan. The results from these tests will provide the necessary data to monitor embrittlement for the CGS vessel.

Materials for the plant-specific materials surveillance program were selected to represent materials used in the reactor beltline region. The specimens were manufactured from a plate actually used in the beltline region and a weld typical of those in the beltline region and thus represent base metal, weld metal, and the transition zone between base metal and weld. The plate and weld were heat treated in a manner which simulates the actual heat treatment performed on the core region shell plates of the completed vessel. WPPSS-ENT-089 (Reference 5.3.4-1) provides additional detail and supporting information for the materials surveillance program.

For the extent of compliance to 10 CFR 50 Appendix H, see Table 5.3-8. NEDO-21708 also addressed the requirements of Appendix H to 10 CFR 50 and supports the current application of Regulatory Guide 1.99.

5.3.1.6.1 Positioning of Surveillance Capsules and Method of Attachment for Plant-Specific Surveillance Program

Surveillance specimen capsules are located at three azimuths at a common elevation in the core beltline region. The sealed capsules are not attached to the vessel but are in welded capsule holders. The capsule holders are mechanically restrained by capsule holder brackets as shown in Figure 5.3-4. The capsule holder brackets allow the capsule holder to be removed at any desired time in the life of the plant for specimen testing. A positive spring-loaded locking device is provided to retain the capsules in position throughout any anticipated event during the lifetime of the vessel.

The capsule holder brackets are designed, fabricated, and analyzed to the requirements of the ASME B&PV Code Section III. The surveillance brackets are welded to the clad material which surfaces the pressure vessel walls. As attached, the brackets do not have to comply with specifications of the ASME Code.

5.3.1.6.2 Time and Number of Dosimetry Measurements

General Electric provides a separate neutron dosimeter so that fluence measurements may be made at the vessel ID during the first fuel cycle to verify the predicted fluence at an early date in plant operation. This measurement is made over this short period to avoid saturation of the dosimeters now available. Once the fluence-to-thermal power output is verified, no further dosimetry is considered necessary because of the linear relationship between fluence and power output.

5.3.1.6.3 Neutron Flux and Fluence Calculations

A description of the methods of analysis for neutron flux and fluence calculations is contained in Sections 4.1.4.5 and 4.3.2.8.

5.3.1.7 Reactor Vessel Fasteners

The reactor vessel closure head (flange) is fastened to the reactor vessel shell flange by multiple sets of threaded studs and nuts. The lower end of each stud is installed in a thread hole in its vessel shell flange. A nut and washer are installed on the upper end of each stud. The proper amount of preload can be applied to the studs by sequential tensioning using hydraulic tensioners. The design and analysis of this area of the vessel is in full compliance with all Section III Class 1 Code requirements. The material for studs, nuts, and washers is SA-540, Grade B23 or B24. The maximum reported ultimate tensile stress for the bolting material was 167,000 psi which is less than the 170,000 psi limitation in Regulatory Guide 1.65. Also the Charpy impact test recommendations of Paragraph IV.A.4 of Appendix G to 10 CFR 50 were not specified in the vessel order since the order was placed prior to issuance of Appendix G to 10 CFR 50. However, impact data from the certified materials report shows that all bolting material has met the Appendix G impact properties. For example, the lowest reported CVN energy was 45 ft-lb at 10°F versus the required 45 ft-lb at 70°F and the lowest reported CVN expansion was 26 mils at 10°F versus the required 25 mils at 70°F.

Hardness tests are performed on all main closure bolting to demonstrate that heat treatment has been properly performed. Studs, nuts, and washers are ultrasonically examined in accordance with Section III, NB-2585 and the following additional requirements:

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

b. Straight beam examination is performed on 100% of each stud. Reference standard for the radial scan is 0.5-in. diameter flat bottom hole having a depth equal to 10% of the material thickness. For the end scan the reference standard is a 0.5-in. flat bottom hole having a depth of 0.5 in. For additional details of the techniques used to examine the reactor vessel studs, see the response to Regulatory Guide 1.65, Revision 0, October 1973, in Section 1.8.

c. Nuts and washers are examined by angle beam from the outside circumference in both the axial and circumferential directions.

There are no metal platings applied to closure studs, nuts, or washers. A phosphate coating is applied to threaded areas of studs and nuts and bearing areas of nuts and washers to act as a rust inhibitor and to assist in retaining lubricant on these surfaces.

5.3.2 PRESSURE-TEMPERATURE LIMITS

5.3.2.1 Limit Curves

Limits on pressure and temperature for inservice leak and hydrostatic tests, normal operation (including heatup and cooldown), and reactor core operation are shown in Figure 5.3-1. The basis used to determine these limits is described in Section 5.3.1.5.

5.3.2.2 Operating Procedures

By comparison of the pressure versus temperature limits in Figure 5.3-1 with intended normal operating procedures for the most severe upset transient, it is shown that the limits will not be exceeded during any foreseeable upset condition. Reactor operating procedures have been established such that actual transients will not be more severe than those for which the vessel design adequacy has been demonstrated. Of the design transients, the upset condition producing the most adverse temperature and pressure condition anywhere in the vessel head and/or shell areas has a minimum fluid temperature of 250°F and a maximum pressure peak of 1180 psig. Scram automatically occurs with initiation of this event, prior to the reduction in fluid temperature, such that the applicable operating limits are bounded by curve A of Figure 5.3-1. Figure 5.3-1 show that at the maximum transient pressure of 1180 psig, the minimum allowable reactor vessel metal temperature conservatively bounds the minimum 250°F reactor fluid temperature.

5.3.3 REACTOR VESSEL INTEGRITY

The reactor vessel was fabricated for GE's Nuclear Energy Division by CBI Nuclear Co., and was subject to the requirements of GE's Quality Assurance program.

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

Energy Northwest's agent provided inspection surveillance of the reactor vessel fabricators in process manufacturing, fabrication, and testing operations in accordance with GE's Quality Assurance program and approved inspection procedures. The reactor vessel fabricator was responsible for the first level inspection of manufacturing, fabrication, and testing activities, and GE was responsible for the first level of audit and surveillance inspection.

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

5.3.3.1 Design

5.3.3.1.1 Description

5.3.3.1.1.1 Reactor Vessel. The reactor vessel shown in Figure 5.3-5 is a vertical, cylindrical pressure vessel of welded construction. The vessel is designed, fabricated, tested, inspected, and stamped in accordance with the ASME Code Section III, Class 1, including the addenda in effect at the date of order placement. Design of the reactor vessel and its support system meets Seismic Category I equipment requirements. The materials used in the reactor pressure vessel are shown in Table 5.2-7.

The cylindrical shell and bottom head sections of the reactor vessel are fabricated of low alloy steel, the interior of which is clad with stainless steel weld overlay. Nozzle and nozzle weld zones are unclad except for those mating to stainless steel piping systems.

Inplace annealing of the reactor vessel is unnecessary because shifts in transition temperature caused by irradiation during the 40-year life can be accommodated by raising the minimum pressurization temperature. Radiation embrittlement is not a problem outside of the vessel beltline region because the irradiation in those areas is less than 1×10^{18} nvt with neutron energies in excess of 1 MeV. The inside diameter and minimum wall thickness of the reactor vessel beltline is provided in Table 5.3-9.

Quality control methods used during the fabrication and assembly of the reactor vessel and appurtenances ensure that design specifications were met. The vessel top head is secured to the reactor vessel by studs and nuts. These nuts are tightened with a stud tensioner. The vessel flanges are sealed with two concentric metal seal rings designed to permit no detectable leakage through the inner or outer seal at any operating condition, including heating to operating pressure and temperature at a maximum rate of 100°F/hr in any 1-hr period. To detect seal failure, a vent tap is located between the two seal rings. A monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal.

5.3.3.1.1.2 Shroud Support. The shroud support is a circular plate welded to the vessel wall. This support is designed to carry the weight of the shroud, shroud head, peripheral fuel elements, neutron sources, core plate, top guide, the steam separators, the jet pump diffusers, jet pump slip joint clamps, and to laterally support the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME Code stress limits.

5.3.3.1.1.3 Protection of Closure Studs. The BWR does not use borated water for reactivity control. This section is therefore not applicable.

5.3.3.1.2 Safety Design Bases

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

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

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

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

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

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

5.3.3.1.3 Power Generation Design Basis

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

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

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

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

5.3.3.1.4 Reactor Vessel Design Data

Reactor vessel design data are contained in Tables 5.2-6 and 5.2-7.

5.3.3.1.4.1 Vessel Support. The concrete and steel vessel support pedestal is constructed as an integral part of the building foundation. Steel anchor bolts set in the concrete extend through the bearing plate and secure the flange of the reactor vessel support skirt to the bearing plate and thus to the support pedestal.

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

5.3.3.1.4.2.1 Control Rod Drive Return Line. To preclude CRD return line cracking on CGS, the return line was deleted and the system modified. The modification consists of adding pressure equalizing valves between the exhaust and cooling water headers and the use of reverse flow through multiple hydraulic control unit (HCU) solenoid valves as the CRD system exhaust flow path. The acceptance of this modification is based on system analyses and performance tests conducted on operating BWRs which have shown satisfactory system operation. The system tests showed that system pressure transients, CRD settling times, and CRD speeds were all unchanged. The tests also showed that all systems functions performed normally.

5.3.3.1.4.3 In-Core Neutron Flux Monitor Housings. Each in-core neutron flux monitor housing is inserted through the in-core penetrations in the bottom head and is welded to the inner surface of the bottom head.

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

5.3.3.1.4.4 Reactor Vessel Insulation. The insulation panels for the cylindrical shell of the vessel are self-supporting, with seismic restraints attached to the sacrificial shield wall. The insulation is designed to be removable over those portions of the vessel where required for the purpose of in-service inspection.

5.3.3.1.4.5 Reactor Vessel Nozzles. All piping connecting to the reactor vessel nozzles has been designed so as not to exceed the allowable loads on any nozzle.

The vessel top head nozzle is provided with a flange with large groove facing. The drain nozzle is of the full penetration weld design. The recirculation inlet nozzles (located as shown in Figure 5.3-5), feedwater inlet nozzles, core spray inlet nozzles, low-pressure coolant injection (LPCI) nozzles, and the CRD hydraulic system return nozzle all have thermal sleeves. Nozzles connecting to stainless steel piping have safe ends or extensions made of

stainless steel. These safe ends or extensions were welded to the nozzles after the pressure vessel was heat treated to avoid furnace sensitization of the stainless steel. The material used is compatible with the material of the mating pipe.

The nozzle for the standby liquid control (SLC) pipe was designed to minimize thermal shock effects on the reactor vessel in the event of injection of cold SLC solution. However, the SLC injection pipe has been relocated to a nozzle on the high-pressure core spray (HPCS) injection line and no longer uses the old nozzle in the bottom head of the reactor pressure vessel. The old nozzle is still in service as the connection for pressure sensing below the core plate, but there is no flow through the nozzle under any operating condition.

In the past, thermal fatigue cracking of feedwater nozzles and vibrational cracking of sparger arms have been observed at other operating BWRs. The mechanisms which have caused cracking in other operating BWRs are understood. A summary discussion of these problems and the solutions incorporated in the CGS design is presented in the following.

A detailed evaluation of the problems of the feedwater nozzle and sparger is presented in NEDE-21821, "BWR Feedwater Nozzle/ Sparger Final Report," March 1978. The solution of the feedwater nozzle and sparger cracking problems involved several elements, including material selection and processing, nozzle clad elimination, and thermal sleeve and sparger redesign. The following summarizes the problems and solutions that have been implemented in the CGS design.

Problem	Cause	Fix
Sparger arm cracks	Vibration	Eliminated clearance between thermal sleeve and safe end
RPV feedwater thermal fatigue	Thermal	Eliminated clad, eliminated leakage with a welded joint between the sparger and safe end

The sparger vibration has been attributed to a self-excitation caused by instability of leakage flow through the annular clearance between the thermal sleeve and safe end. Tests have shown that the vibration is eliminated if the clearance is reduced sufficiently or sealed. The solution that was selected for CGS uses a welded joint to ensure no leakage. This feature is also an essential part of the solution of the nozzle cracking problem. Freedom from vibration over a range of conditions has been demonstrated by the tests reported in NEDE-23604 (see Figures 5.3-6 and 5.3-7).

The cracking of the feedwater nozzles is a two-part process. The crack initiation mechanism as discussed above is the result of self-initiated thermal cycling. If this were the only mechanism present, the cracks would initiate, grow to a depth of approximately 0.25 in., and arrest. This degree of cracking could be tolerated; however, there is another mechanism which supports crack growth. This mechanism is the system induced transients, primarily the startup/shutdown transients. Because of CGS's welded thermal sleeve arrangement, leakage flow is eliminated and the heat transfer between the feedwater and the nozzle are reduced to the point where the thermal stresses in the nozzle are not high enough to cause a significant crack growth. Analyses presented in NEDE-21821, Section 4.7, demonstrated the benefits of the welded thermal sleeve and of using unclad nozzles. With these demonstrated benefits and inservice surveillance, CGS found it unnecessary to install instrumentation for design verification.

CGS has installed two automatic feedwater low flow control valves, RFW-FCV-10A and 10B. These valves have the capacity to control flow down to 362 gpm, or about 1.25% of total flow. This valve configuration will substantially reduce the temperature differential between the feedwater and the water in the RPV during low power operation, also reducing the thermal stresses in the nozzle.

5.3.3.1.4.6 Materials and Inspection. The reactor vessel was designed and fabricated in accordance with the appropriate ASME B&PV Code as defined in Section 5.2.1.2. Table 5.2-7 defines the materials and specifications. Table 5.3-8 defines the compliance with reactor vessel material surveillance program requirements.

5.3.3.1.4.7 Reactor Vessel Schematic (BWR). The reactor vessel schematic is contained in Figure 5.3-3. Trip system water levels are indicated as shown.

5.3.3.2 Materials of Construction

All materials used in the construction of the reactor pressure vessel conform to the requirements of ASME Code Section II materials. The vessel heads, shells, flanges, and nozzles are fabricated from low alloy steel plate and forgings purchased in accordance with ASME specifications SA533 Grade B Class 1 and SA-508 Class 2. Special requirements for the low alloy steel plate and forgings are discussed in Section 5.3.1.2. Cladding employed on the interior surfaces of the vessel consists of austenitic stainless steel weld overlay.

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

5.3.3.3 Fabrication Methods

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

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

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

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

5.3.3.4 Inspection Requirements

All plate, forgings, and bolting were 100% ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Section III requirements. Welds on the reactor pressure vessel were examined in accordance with methods prescribed and met the acceptance requirements specified by ASME Section III. In addition, the pressure-retaining welds were ultrasonically examined using acceptance standards which were required by ASME Section XI.

5.3.3.5 Shipment and Installation

The completed reactor vessel was given a thorough cleaning and examination prior to shipment. The vessel was tightly sealed for shipment to prevent entry of dirt or moisture. Preparations for shipment were in accordance with detailed written procedures. On arrival at the reactor site the reactor vessel was carefully examined for evidence of any contamination as a result of damage to shipping covers. Suitable measures were taken during installation to ensure that vessel integrity was maintained; for example, access controls were applied to

personnel entering the vessel, weather protection was provided, periodic cleanings were performed, and only approved miscellaneous materials were used during assembly.

5.3.3.6 Operating Conditions

Restrictions on plant operation to hold thermal stresses within acceptable ranges are included in the Technical Specifications. These restrictions on coolant temperature are

a. The average rate of change of reactor coolant temperature during normal heatup and cooldown,

b. Coolant temperature difference between the dome (inferred from P_{sat}) and the bottom head drain, and

c. Idle reactor recirculation loop and average reactor coolant temperature differential.

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

The above operational limits when maintained insure that the stress limits within the reactor vessel and its components are within the thermal limits to which the vessel was designed for normal operating conditions. To maintain the material integrity of the vessel in the event that these operational limits are exceeded the reactor vessel has also been designed to withstand a limited number of transients caused by operator error. Reactor vessel material integrity is also maintained during abnormal operating conditions where safety systems or controls provide an automatic response in the reactor vessel. The special and transient events considered in the design of the vessel are discussed or referenced in Section 5.2.2.

5.3.3.7 Inservice Surveillance

Inservice inspection of the reactor pressure vessel is in accordance with the requirements as discussed in Section 5.2.4. The vessel was examined once prior to startup to satisfy the preoperational requirements of IS-232 or the ASME Code, Section XI. Subsequent inservice

inspection will be scheduled and performed in accordance with the requirements of 10 CFR 50.55a subparagraph (g).

The materials surveillance program monitors changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and thermal environment. See Section 5.3.1.6 for description of the materials surveillance program. Operating procedures will be modified in accordance with test results to ensure adequate brittle fracture control.

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

5.3.4 REFERENCES

5.3.4-1 WPPSS-ENT-089, “WNP-2 RPV Surveillance Program,” Current Revision.

5.3.4-2 BWRVIP-86, Revision 1-A, “BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan,” Final Report, October 2012.

Table 5.3-1

10 CFR 50 Appendix G Matrix

Appendix G Paragraph	Topic	Comply Yes/No or N/A	Alternative Actions or Comments
I, II	Introduction; Definitions	--	
III.A	Compliance with ASME Code, Section NB-2300	Yes	See Section 5.3.1.5.2 for discussion.
III.B.1	Location and Orientation of Impact Test Spec	Yes	See III.A above.
III.B.2	Materials Used to Prepare Test Specimens	No	Compliance except for CVN orientation and CVN upper shelf.
III.B.3	Calibration of Temperature Instruments and Charpy Test Machines	No	Paragraph NB-2360 of the ASME B&PV Code Section III was not in existence at the time of purchase of the CGS reactor pressure vessel. However, the requirements of the 1971 edition of the ASME B&PV Section III code, Summer 1971 addenda, were met. For the discussions of the GE interpretations of compliance and NRC acceptance see References 1 and 2. The temperature instruments and Charpy Test Machines calibration data are retained until the next recalibration. This is in accordance with Regulatory Guide 1.88, Revision 2, GE Alternative Position 1.88, and ANSI N45.2.9-1974. Therefore, the instrument calibration data for CGS would not be currently available.
III.B.4	Qualification of Testing Personnel	No	No written procedures were in existence as required by the regulation; however, the individuals were qualified by on-the-job training and past experience. For the discussion of the GE interpretation of compliance and NRC acceptance see References 1 and 2.
III.B.5	Test Results Recording and Certification	Yes	See References 1 and 2.
III.C.1	Test Conditions	No	See III.A, III.B.2 above.

Table 5.3-1

10 CFR 50 Appendix G Matrix (Continued)

Appendix G Paragraph	Topic	Comply Yes/No or N/A	Alternative Actions or Comments
III.C.2	Materials Used to Prepare Test Specimens for Reactor Vessel Beltline	Yes	Compliance on base metal and weld metal tests. Test weld not made on same heat of base plate necessarily.
IV.A.1	Acceptance Standard of Materials	--	
IV.A.2.a	Calculates Stress Intensity Factor	Yes	
IV.A.2.b	Requirements for Nozzles, Flanges, and Shell Region Near Geometric Discontinuities	No	Plus 60°F was added to the RT_{NDT} for the reactor vessel flanges. For feedwater nozzles the results of the BWR/6 analysis was adjusted to CGS RT_{NDT} conditions.
IV.A.2.c	RPV Metal Temperature Requirement When Core is Critical	Yes	Comply with 10 CFR 50 Appendix G.
IV.A.2.d	Minimum Permissible Temperature During Hydro Test	Yes	
IV.A.3	Materials for Piping, Pumps, and Valves	No	Main steam line piping is in compliance. See 5.2.3.3 for discussions on pumps and valves.
IV.A.4	Materials for Bolting and Other Fasteners	Yes	Current toughness requirements for closure head studs are met at +10°F even though testing was done per the 1971 ASME code.
IV.B	Minimum Upper Shelf Energy for RPV Beltline	No	Weld and longitudinal CVN data were taken at -20°F and +10°F only. An estimate of compliance to requirements should be made from the first surveillance capsule results per MTEB 5-2.

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Table 5.3-1

10 CFR 50 Appendix G Matrix (Continued)

Appendix G Paragraph	Topic	Comply Yes/No or N/A	Alternative Actions or Comments
IV.B (continued)			Beltline plates were tested with longitudinal CVNs at +10°F only. The minimum values are for Heat C1272-1 (0.15% Cu; 34, 26, 30, 31, 34, 30 ft-lb; 10 and 40% shear at +10°F) and Heat C1273-1 (0.14% Cu; 33, 33, 30, 30, 34, 35 ft-lb; 10% shear at +10°F). Beltline welds were tested with CVNs at 10°F or -20°F only. Lowest weld values are found for Heat 04P046/Lot D217A27A (0.06% Cu; 34, 36, 37, 39, 40 ft-lb; 20 and 30% shear at -20°F). Heat C3L46C/Lot J020A27A (0.02% Cu; 35, 39, 40 ft-lb; 60% shear at +10°F) and Heat 05P018/Lot D211A27A (0.09% Cu; 29, 30, 31, 36, 38 ft-lb; 30 and 40% shear at -20°F). Because of the preceding relatively low test temperatures and Cu contents, it is anticipated that end-of-life upper shelf CVN values would be in excess of 50 ft-lb.
IV.C	Requirements for Annealing when RT_{ndt} >200	N/A	
V.A	Requirements for Material Surveillance Program	See Table 5.3-8	
V.B	Conditions for Continued Operation	Yes	Requirements for continued operations are covered in Technical Specifications and the Reactor Pressure Vessel Surveillance Program document (WPPSS-ENT-089, Reference 5.3.4-1). See Section 5.3.1.6 for description of the Materials Surveillance Program.
V.C	Alternative if V.B Cannot be Satisfied	N/A	The Surveillance Program demonstrates compliance with Appendix G, Section IV. See Section 5.3.1.6 for description of the Materials Surveillance Program.

Table 5.3-1

10 CFR 50 Appendix G Matrix for (Continued)

Appendix G Paragraph	Topic	Comply Yes/No or N/A	Alternative Actions or Comments
V.D	Requirement for RPV Thermal Annealing if V.C Cannot be Met	N/A	
V.E	Reporting Requirements for V.C and V.D	N/A	

REFERENCES

1. Letter MFN-414-77 from G. G. Sherwood, GE, to Edson G. Case, NRC, dated October 17, 1977.

2. Letter from Robert B. Minoque, NRC, to G. G. Sherwood, GE, dated February 14, 1978.

Table 5.3-2

Plate Material Cross Reference

	Heat	Slab
Ring 21		
PCMK 21-1-1	C1272	1
PCMK 21-1-2	C1273	1
PCMK 21-1-3	C1273	2
PCMK 21-1-4	C1272	2
Ring 22		
PCMK 22-1-1	B5301	1
PCMK 22-1-2	C1336	1
PCMK 22-1-3	C1337	1
PCMK 22-1-4	C1337	2

Table 5.3-3

Weld Material Cross Reference

Weld Identification	Type	Heat	Lot
AB - Girthweld	E8018NM	492L4871	A422B27AF
	RAC01NMM	5P6756	0342
	RAC01NMM	3P4955	0342
	E8018NM	04T931	A423B27AG
Ring 21			
BA	E8018NM	04P046	D217A27A
	E8018NM	07L669	K004A27A
	RAC01NMM	3P4966	1214
BB	E8018NM	04P046	D217A27A
	E8018NM	07L669	K004A27A
	E8018NM	C3L46C	J020A27A
	RAC01NMM	3P4966	1214
	E8018NM	08M365	G128A27A
BC	E8018NM	09L853	A111A27A
	E8018NM	C3L46C	J020A27A
	RAC01NMM	3P4966	1214
BD	E8018NM	C3L46C	J020A27A
	RAC01NMM	3P4966	1214
	E8018NM	04P046	D217A27A
	E8018NM	C3L46C	J020A27A
Ring 22			
BE	RAC01NMM	3P4966	1214
BF	E8018NM	04P046	D217A27A
	E8018NM	05P018	D211A27A
	RAC01NM	3P4966	1214
BG	E8018NM	624063	C228A27A
	E8018NM	624039	D224A27A
	RAC01NMM	3P4966	1214
BH	E8018NM	04P096	D217A27A
	E8018NM	624039	D205A27A
	RAC01NMM	3P4966	1214

Table 5.3-4

Plate Material

	Charpy Impact ft-lb @ +10°F	Charpy Expansion MLE	Drop Weight NDT (°F)	RT_{NDT} (°F)
Ring 21				
PCMK 21-1-1 Heat C1272-1	34, 26, 30/31, 34, 30	30, 34, 24/27, 26, 32	–10	28
PCMK 21-1-2 Heat C1273-1	33, 33, 30/30, 34, 35	30, 31, 27/26, 34, 32	–20	20
PCMK 21-1-3 Heat C1273-2	38, 48, 55/66, 61, 71	44, 39, 34/53, 52, 56	–30	4
PCMK 21-1-4 Heat C1272-2	40, 42, 44/51, 55, 50	32, 36, 38/41, 44, 42	–30	0
Ring 22				
PCMK 22-1-1 Heat B5301-1	64, 62, 66/52, 52, 55	56, 56, 56/45, 44, 44	–30	–20
PCMK 22-1-2 Heat C1336-1	70, 72, 71/60, 44, 66	59, 60, 62/56, 41, 51	–30	–8
PCMK 22-1-3 Heat C1337-1	71, 76, 74/70, 72, 55	61, 60, 60/63, 61, 52	–30	–20
PCMK 22-1-4 Heat C1337-2	62, 72, 82/73, 67, 73	51, 61, 66/52, 59, 61	–50	–20

Table 5.3-5

Weld Material

Type/Heat/Lot/Control	Charpy Impact (ft-lb)	Charpy Expansion MLE	Charpy Test Temperature (°F)	RT_{NDT} (°F)
Girth Weld AB				
E8018NM/492L4871 Lot A422B27AF	78, 82, 105, 93, 81	55, 60, 72, 74, 60	–20[a]	–50
RAC01NMM/5P6756[b] Lot 0342	76, 79, 77, 80, 72	64, 72, 55, 69, 60	+10	–50
RAC01NMM/5P6756[c] Lot 0342	76, 79, 77, 80, 72	64, 72, 55, 69, 60	+10	–50
RAC01NMM/3P4955[b] Lot 0342	49, 63, 47, 49, 64	39, 48, 36, 43, 57	+10	–20
RAC01NMM/3P4955[c] Lot 0342	52, 37, 45, 55, 33	44, 30, 43, 50, 32	+10	–16
E8018NM/04T931 Lot A423B27AG	86, 84, 102, 63, 61	69, 58, 60, 57, 70	–20	–50
Ring 21BA				
E8018NM/04P046 Lot D217A27A	34, 36, 37, 39, 40	23, 28, 24, 20, 24	–20[a]	–48
E8018NM/07L669 Lot K004A27A	50, 50, 54	44, 44, 46	+10[a]	–50
RAC01NMM/3P4966[c] Lot 1214/3482	40, 71, 75, 63, 59	41, 63, 68, 58, 53	+10[a]	–30
RAC01NMM/3P4966[b] Lot 1214/3482	65, 70, 67, 69, 49	60, 60, 63, 55, 44	+10[a]	-48
Ring 21BB				
E8018NM/04P046 Lot D217A27A	34, 36, 37, 39, 40	23, 28, 24, 20, 24	–20[a]	–48
E8018NM/07L669 Lot K004A27A	50, 50, 54	44, 44, 46	+10[a]	–50
E8018NM/C3L46C Lot J020827A	35, 39, 40	34, 39, 39	+10[a]	–20

Table 5.3-5

Weld Material (Continued)

Type/Heat/Lot/Control	Charpy Impact (ft-lb)	Charpy Expansion MLE	Charpy Test Temperature (°F)	RT_{NDT} (°F)
RAC01NMM/3P4966[c] Lot 1214/3482	40, 71, 75, 63, 59	41, 63, 68, 58, 53	+10[a]	–30
RAC01NMM/3P4966[b] Lot 1214/3482	65, 70, 67, 69, 49	60, 60, 63, 55, 44	+10[a]	–48
E8018NM/08M365 Lot G128A27A	49, 50, 51	38, 40, 43	+10[a]	–48
Ring 21BC				
E8018NM/09L853 Lot A111A27A	78, 78, 79	60, 62, 62	+10[a]	–50
E8018NM/C3L46C Lot J020A27A	35, 39, 40	34, 39, 39	+10[a]	–20
RAC01NMM/3P4966[c] Lot 1214/3482	40, 71, 75, 63, 59	41, 63, 68, 58, 53	+10[a]	–30
RAC01NMM/3P4966[b] Lot 1214/3482	65, 70, 67, 69, 49	60, 60, 63, 55, 44	+10[a]	–48
Ring 21BD				
E8018NM/C3L46C Lot J020A27A	35, 39, 40	34, 39, 39	+10[a]	–20
RAC01NMM/3P4966[c] Lot 1214/3482	40, 71, 75, 63, 59	41, 63, 68, 58, 53	+10[a]	–30
RAC01NMM/3P4966[b] Lot 1214/3482	65, 70, 67, 69, 49	60, 60, 63, 55, 44	+10[a]	–48
E8018NM/04P046 Lot D217A27A	34, 36, 37, 39, 40	23, 28, 24, 20, 24	–20[a]	–48
Ring 22BE				
RAC01NMM/3P4966[c] Lot 1214/3481	39, 38, 38, 82, 84	68, 64, 63, 81, 72	+10	–20
RAC01NMM/3P4966[b] Lot 1214/3481	28, 84, 63, 75, 78	18, 62, 57, 51, 57	+10	–6

Table 5.3-5

Weld Material (Continued)

Type/Heat/Lot/Control	Charpy Impact (ft-lb)	Charpy Expansion MLE	Charpy Test Temperature (°F)	RT_{NDT} (°F)
Ring 22BF				
E8018NM/04P046 Lot D217A27A	34, 36, 37, 39, 40	23, 28, 24, 20, 24	–20[a]	–48
E8018NM/05P018 Lot D211A27A	29, 30, 31, 36, 38	26, 26, 31, 33, 35	–20[a]	–38
RAC01NMM/3P4966[c] Lot 1214/3481	39, 38, 38, 82, 84	68, 64, 63, 81, 72	+10	–20
RAC01NMM/3P4966[b] Lot 1214/3481	28, 84, 63, 75, 78	18, 62, 57, 51, 57	+10	–6
Ring 22BG				
E8018NM/624063 Lot C228A27A	37, 40, 51, 57, 70	33, 34, 41, 47, 55	–20[a]	–50
E8018NM/624039 Lot D224A27A	28, 33, 34, 36, 42	29, 32, 33, 34, 42	–20[a]	–36
RAC01NMM/3P4966[c] Lot 1214/3481	39, 38, 38, 82, 84	68, 64, 63, 81, 72	+10	–20
RAC01NMM/3P4966[b] Lot 1214/3481	28, 84, 63, 75, 78	18, 62, 57, 51, 57	+10	–6
Ring 22BH				
E8018NM/04P046 Lot D217A27A	34, 36, 37, 39, 40	23, 28, 24, 20, 24	–20[a]	–48
E8018NM/624039 Lot D205A27A	41, 44, 49, 54, 58	32, 36, 40, 41, 45	–20[a]	–50
RAC01NMM/3P4966[c] Lot 1214/3481	39, 38, 38, 82, 84	68, 64, 63, 81, 72	+10	–20
RAC01NMM/3P4966[b] Lot 1214/3481	28, 84, 63, 75, 78	18, 62, 57, 51, 57	+10	–6

[a] Drop weight NDT not applicable.
[b] Tandem wire process.
[c] Single wire process.

Table 5.3-6

Vessel Beltline Plate

Plate	P	Cu	C	Mn	Si	S	Ni	Mo	V
C1272-1	0.013	0.15	0.23	1.31	0.26	0.02	0.60	0.55	--
C1272-2	0.013	0.15	0.23	1.31	0.26	0.02	0.60	0.55	--
C1273-1	0.014	0.14	0.23	1.28	0.23	0.018	0.60	0.57	--
C1273-2	0.014	0.14	0.23	1.28	0.23	0.018	0.60	0.57	--
B5301-1	0.017	0.13	0.20	1.34	0.23	0.014	0.50	0.52	--
C1336-1	0.017	0.13	0.21	1.36	0.22	0.013	0.50	0.49	--
C1337-1	0.018	0.15	0.22	1.32	0.21	0.013	0.51	0.50	--
C1337-2	0.018	0.15	0.22	1.32	0.21	0.013	0.51	0.50	--

Peak I.D. EOL (33.1 EFPY) fluence = 7.41 x 10^{17} n/cm^2.

Table 5.3-7

Vessel Beltline Weld Material Chemistry[a]

Weld Heat/Control	Cu	C	Mn	Si	S	Ni	Mo	V	P
492L4871[b]	0.03	0.07	1.17	0.32	0.02	0.98	0.51	0.02	0.02
5P6756/0342[c]	0.08[f]	0.063	1.27	0.57	0.011	0.936[f]	0.45	0.006	0.01
5P6756/0342[d]	0.08[f]	0.078	1.24	0.53	0.012	0.936[f]	0.46	0.006	0.01
3P4955/0342[d]	0.027[f]	0.035	1.33	0.56	0.011	0.921[f]	0.52	0.006	0.016
3P4955/0342[c]	0.027[f]	0.054	1.28	0.55	0.010	0.921[f]	0.54	0.007	0.016
04T931[b]	0.03	0.05	1.03	0.28	0.024	1.00	0.53	0.01	0.02
04P046[b]	0.06	0.044	1.04	0.40	0.021	0.90	0.58	0.02	0.009
07L996[b]	0.03	0.05	1.24	0.48	0.016	1.02	0.54	--	0.014
3P4966/3481[d]	0.025[f]	0.074	1.38	0.36	0.013	0.913[f]	0.49	0.006	0.010
3P4966/3481[c]	0.025[f]	0.067	1.39	0.38	0.014	0.913[f]	0.53	0.008	0.011
3P4966/3482[c]	0.025[f]	0.059	1.35	0.38	0.013	0.913[f]	0.50	0.005	0.013
3P4966/3482[d]	0.025[f]	0.077	1.42	0.41	0.013	0.913[f]	0.53	0.005	0.014
CL46C[b]	0.02	0.063	0.96	0.32	0.017	0.87	0.53	--	0.019
08M365[b]	0.02	0.057	1.23	0.47	0.023	1.10	0.57	--	0.02
09L853[b]	0.03	0.052	1.23	0.46	0.023	0.86	0.51	--	0.018
05P018[b]	0.09	0.057	1.21	0.44	0.021	0.90	0.53	0.01	0.008
624063[b]	0.03	0.041	1.12	0.41	0.018	1.00	0.54	0.01	0.009
624039[b,e]	0.07	0.060	1.11	0.45	0.025	1.01	0.57	0.02	0.015
624039[b,e]	0.10	0.041	1.12	0.45	0.02	0.92	0.53	0.01	0.01

[a] As deposited.
[b] M = Manual Welding Process
[c] S = Single Wire Process
[d] T = Tandem Wire Process
[e] Different lot numbers
[f] GE Nuclear Energy, "Pressure-Temperature Curves for Energy Northwest Columbia," NEDC-33144-P (CVI CAL 1012-00,3), Table 4-6b.

Table 5.3-8

10 CFR 50 Appendix H Matrix

Appendix H Paragraph	Topic	Comply Yes/No or N/A	Alternative Actions or Comments
I	Introduction	N/A	
II.A	Fluence 10^{17}n/cm^2	Yes	CGS Plant-specific RPV Surveillance Program is replaced by the BWRVIP ISP. See Section 5.3.1.6.
II.B	Standards Requirements (ASTM) for Surveillance	No	Plant-specific Surveillance Program: Noncompliance with ASTM E185-73 in that the surveillance specimens are not necessarily from the limiting beltline material. Specimens are from actual beltline material, however, and can be used to predict behavior of the limiting material. Heat and heat/lot numbers for surveillance specimens were supplied. See Section 5.3.1.6.
II.C.1	Surveillance Specimen Shall be Taken for Locations Alongside the Fracture Test Specimens (Section III.B of Appendix G)	No	Plant-specific Surveillance Program: Noncompliance in that specimens may not have necessarily been taken from alongside specimens required by Section III of Appendix G and transverse CVNs may not be employed. However, representative materials have been used, and RT_{NDT} shift appears to be independent of specimen orientation. See Section 5.3.1.6.
II.C.2	Locations of Surveillance Capsules in RPV	Yes	Code basis is used for attachment of brackets to vessel cladding.
II.C.3.a	Withdrawal Schedule of Capsules, $RT_{NDT} < 100°F$	N/A	See Section 5.3.1.6. Starting RT_{NDT} of limiting material is based on alternative action (see paragraph III.A of Appendix G).
II.C.3.b	Withdrawal Schedule of Capsules, $RT_{NDT} < 200°F$	N/A	
II.C.3.c	Withdrawal Schedule of Capsules, $RT_{NDT} > 200°F$	N/A	

Table 5.3-8

10 CFR 50 Appendix H Matrix (Continued)

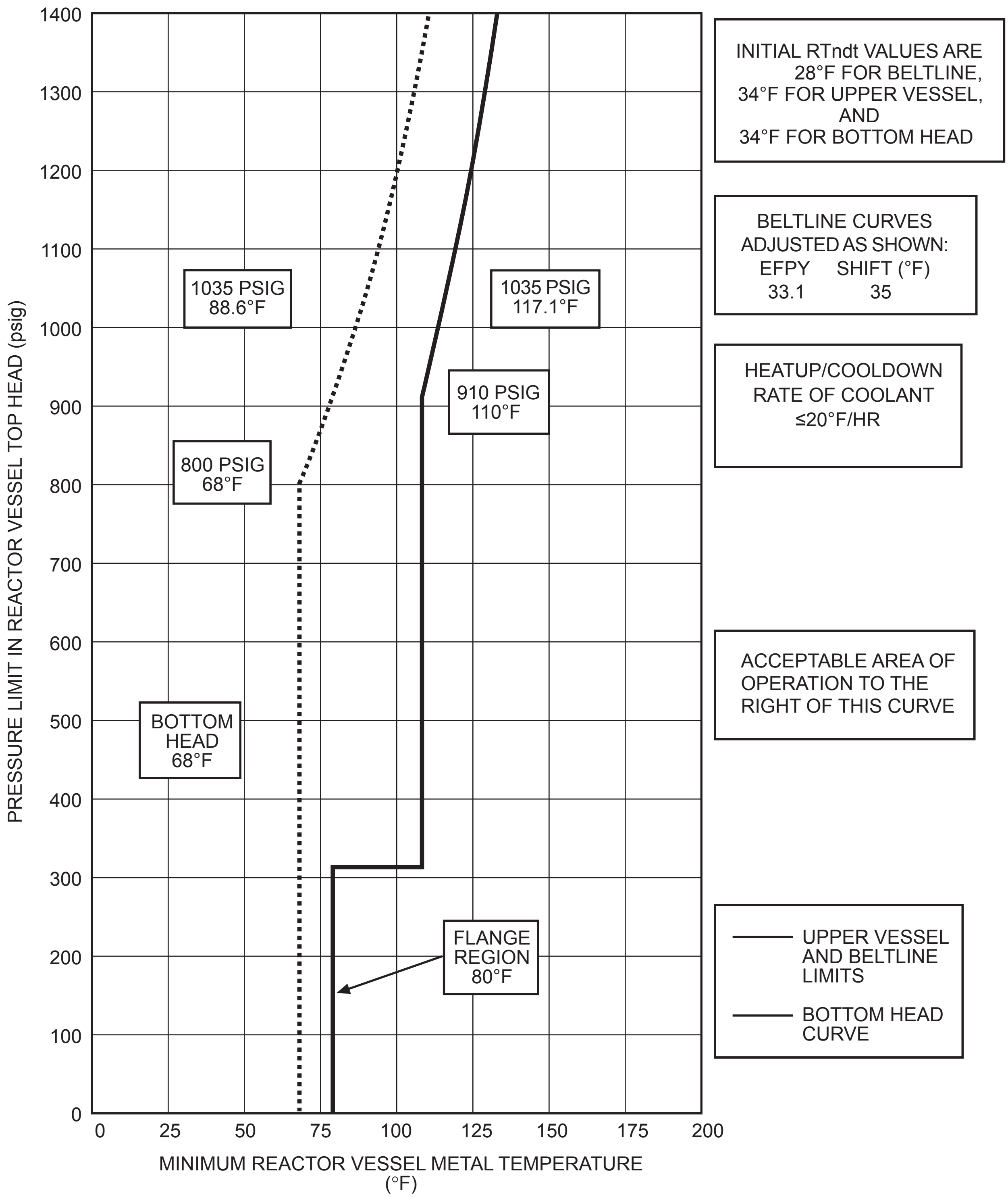
Appendix H Paragraph	Topic	Comply Yes/No or N/A	Alternative Actions or Comments
III.A	Fracture Toughness Testing Requirements of Specimens	Yes	Requirements for postirradiation testing of surveillance material are addressed in the BWRVIP ISP implementation plan (Reference 5.3.4-2).
III.B	Method of Determining Adjusted Reference Temperature for Base Metal, HAZ, and Weld Metal	Yes	Method of determining adjusted reference temperatures found in the BWRVIP ISP implementation plan (Reference 5.3.4-2).
IV.A	Reporting Requirements of Test Results	Yes	Reporting requirements are discussed in the BWRVIP ISP implementation plan (Reference 5.3.4-2).
IV.B	Requirement for Dosimetry Measurement	Yes	Dosimetry requirements are discussed in the BWRVIP ISP implementation plan (Reference 5.3.4-2).
IV.C	Reporting Requirements of Pressure/Temperature Limits	Yes	A discussion of the pressure/temperature limits and reporting requirements is found in the BWRVIP implementation plan (Reference 5.3.4-2).

Table 5.3-9

Reactor Vessel Beltline Minimum
Wall Thickness and Diameter

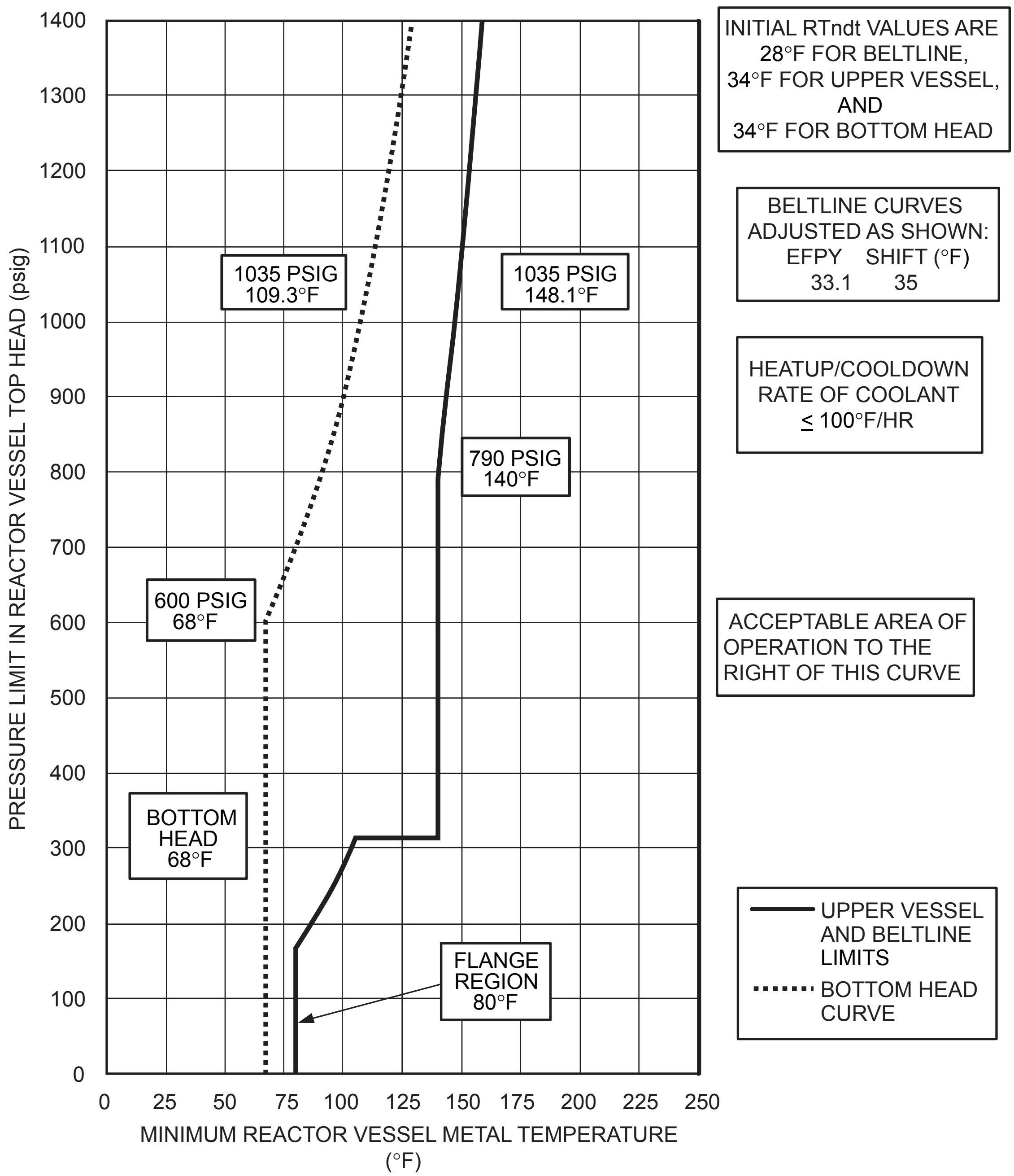
Inside diameter with clad	= 251 in. (minimum)
Wall thickness (ring #22, lower intermediate shell)	= 6.188 in. (minimum)
Wall thickness (ring #21, lower shell)	= 9.5 in. (minimum)
Clad thickness	= 0.1875 in. (nominal)
	= 0.125 in. (minimum)

Refer to Figure 5.3-2 and CVI 02B13-06,2 Rev. 8 (VPF #3133-001-9) CBI Nuclear Company Drawing No. 1, Rev. 8, "Vessel Outline."

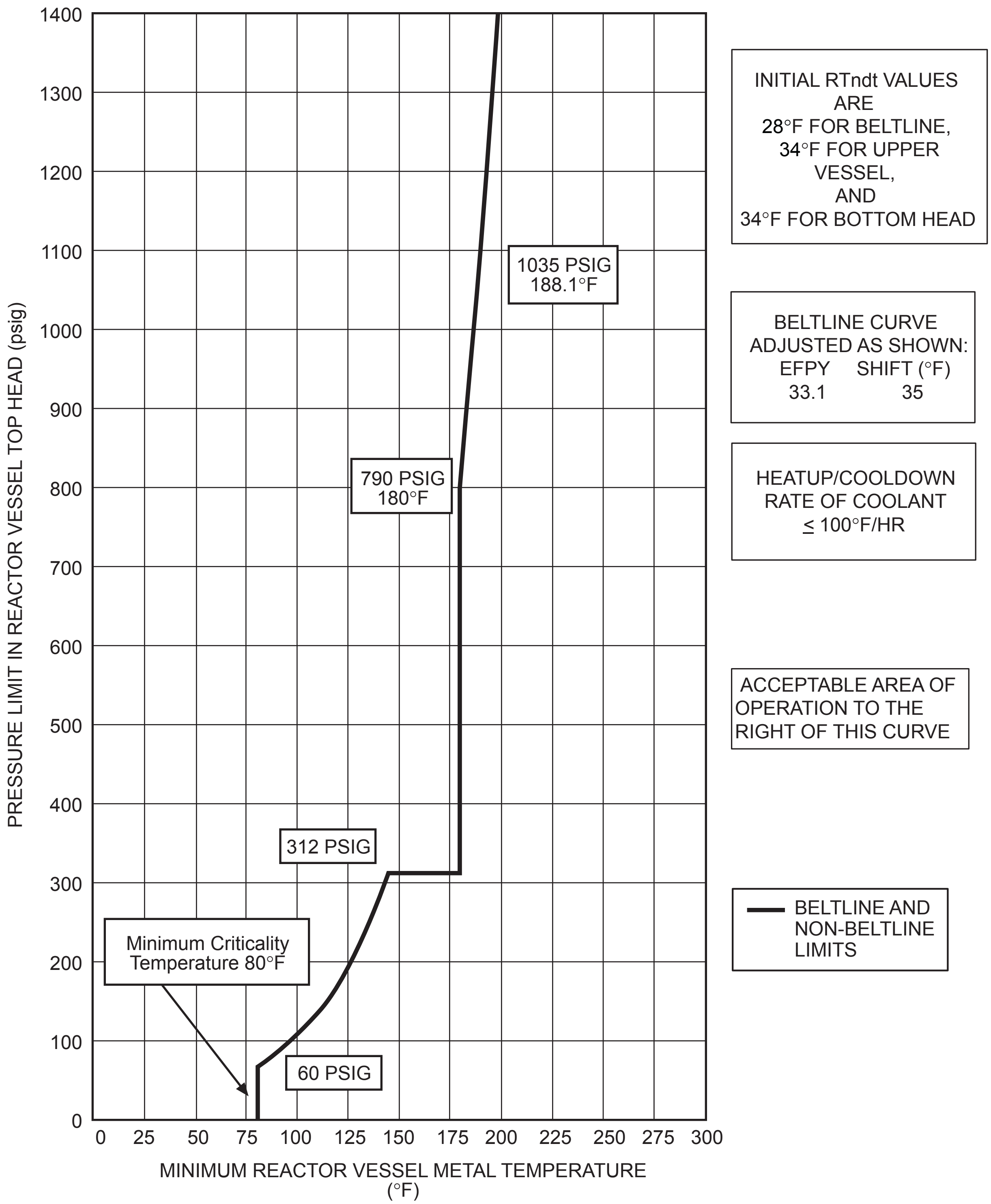


Columbia Generating Station Final Safety Analysis Report	Pressure Temperature Limits Testing Curve A (Inservice Leak and Hydrostatic Testing Curve)	
	Draw. No. 900547.42	Rev.	Figure 5.3-1.1

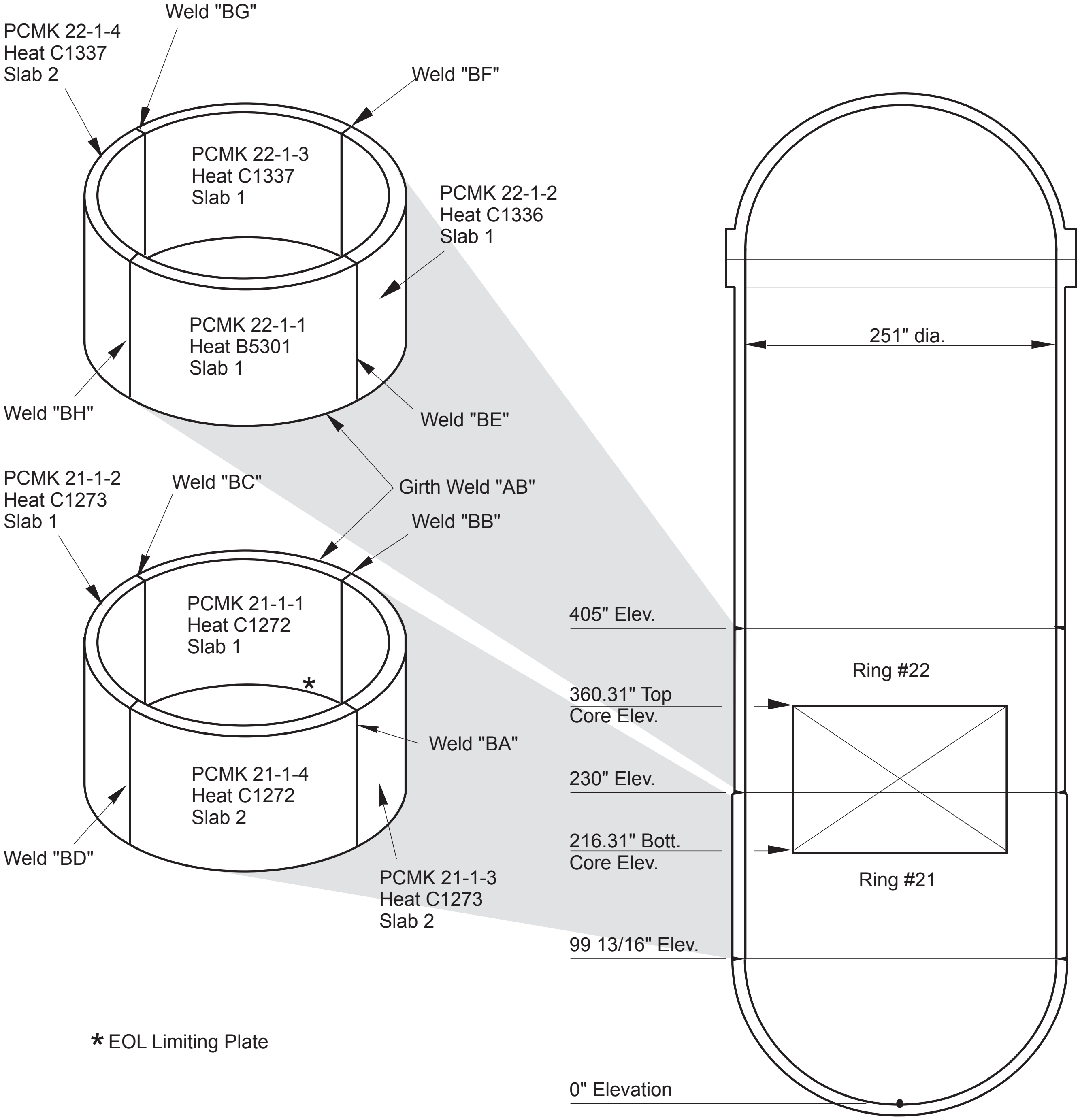
Form No. 960690FH
LDCN-04-005



Columbia Generating Station Final Safety Analysis Report	Pressure Temperature Limits Curve B (Non-Nuclear Heating and Cooldown Curve)		
	Draw. No. 990578.74	Rev.	Figure 5.3-1.2



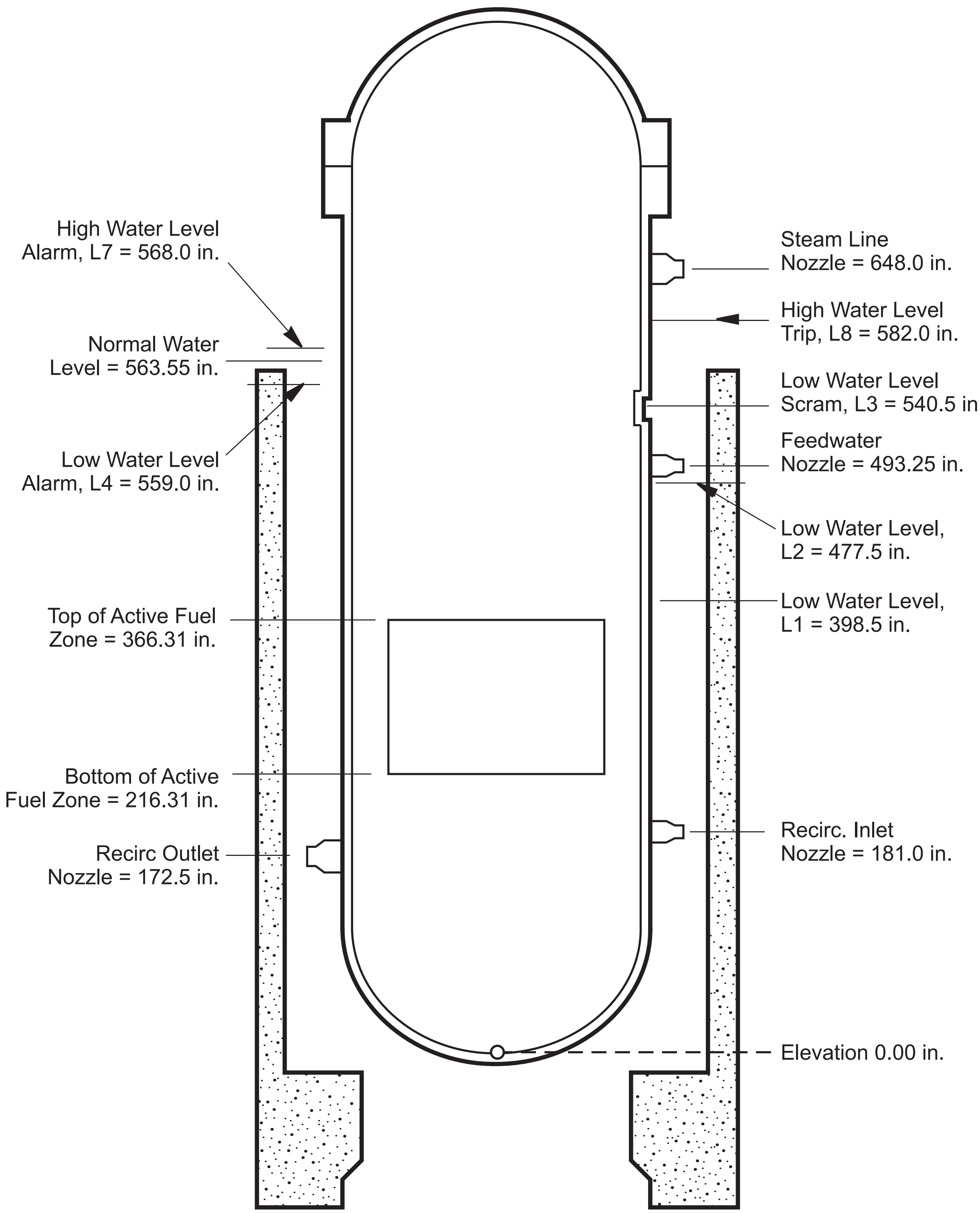
Columbia Generating Station Final Safety Analysis Report	Pressure Temperature Limits Curve C (Nuclear Heating and Cooldown Curve)
	Draw. No. 900547.43 | Rev. | Figure 5.3-1.3



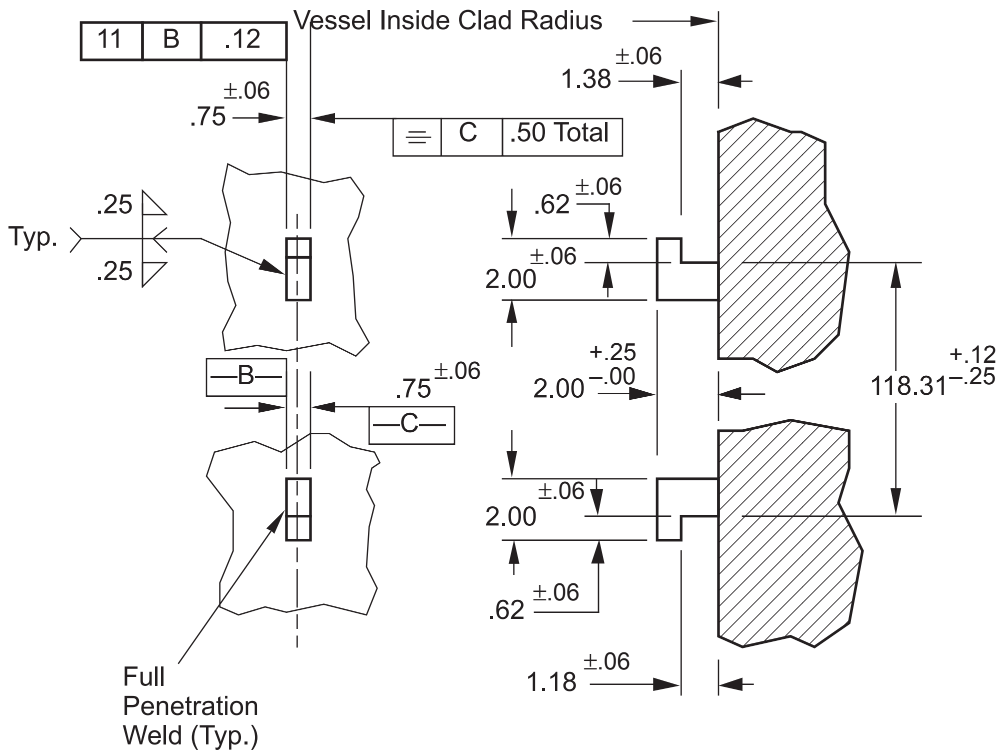
Columbia Generating Station
Final Safety Analysis Report

Vessel Beltline Plate and Weld Seam Identification

Draw. No. 910402.30	Rev.	Figure 5.3-2



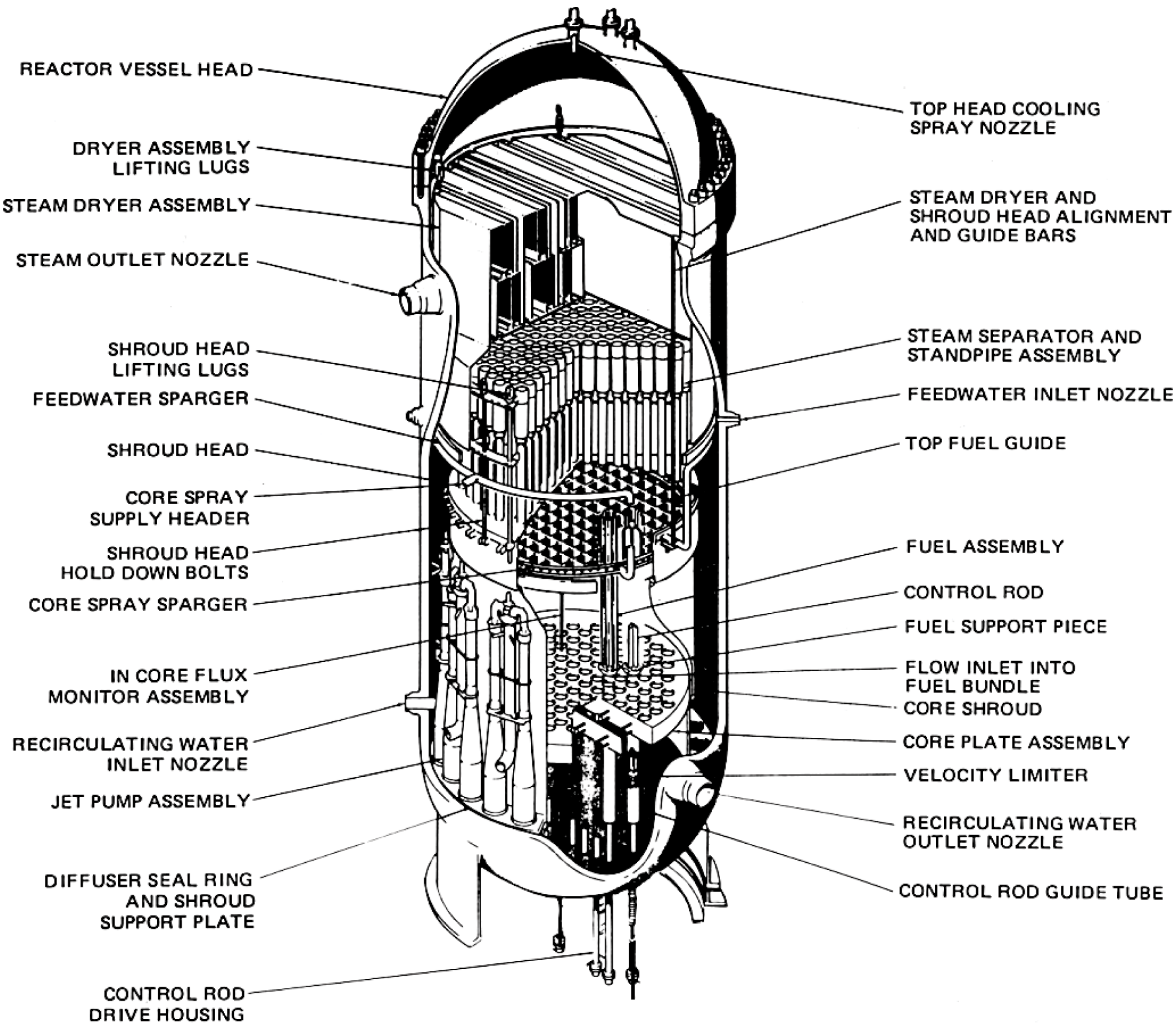
Columbia Generating Station **Final Safety Analysis Report**	**Nominal Reactor Vessel Water Level Trip and Alarm Elevation Settings**
Draw. No. 960690.53	Rev. / Figure 5.3-3



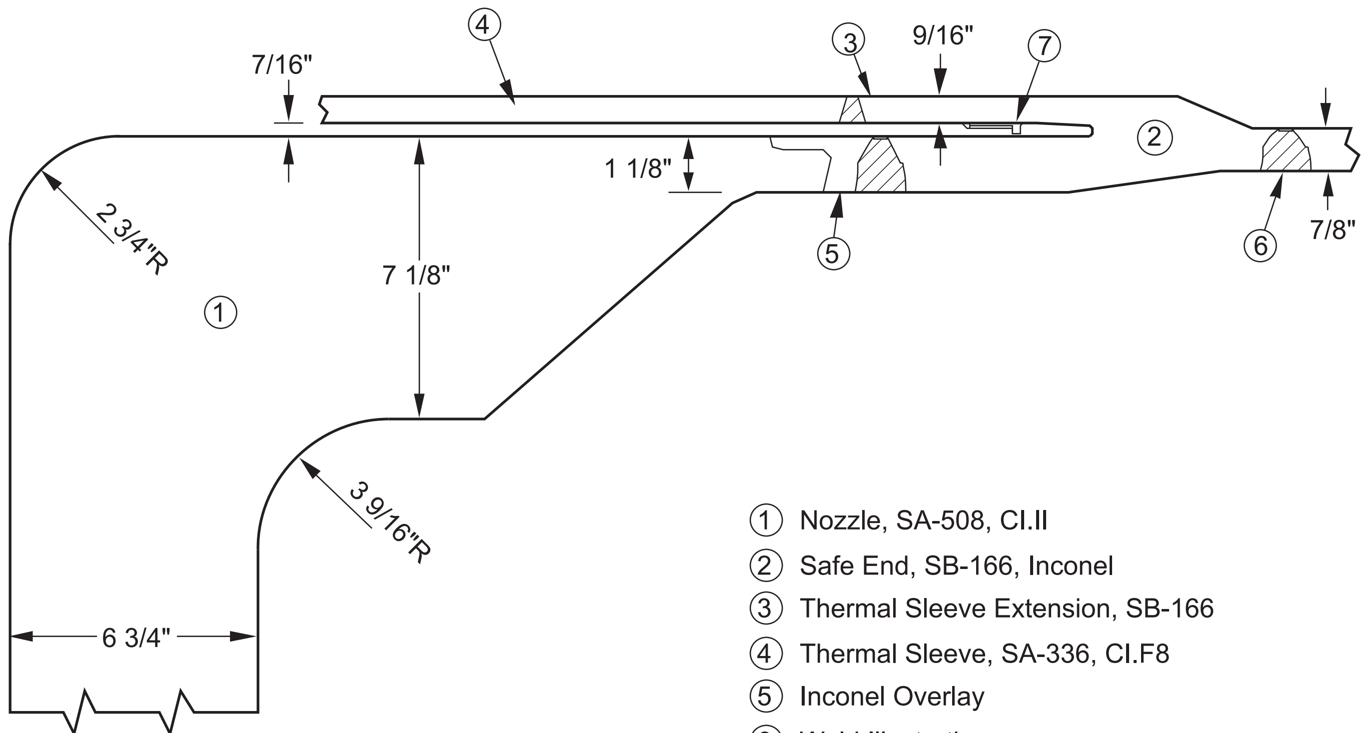
Columbia Generating Station
Final Safety Analysis Report

Bracket for Holding Surveillance Capsule

Draw. No. 960690.54 | Rev. | Figure 5.3-4



Columbia Generating Station Final Safety Analysis Report	Reactor Vessel		
	Draw. No. 020002.44	Rev.	Figure 5.3-5



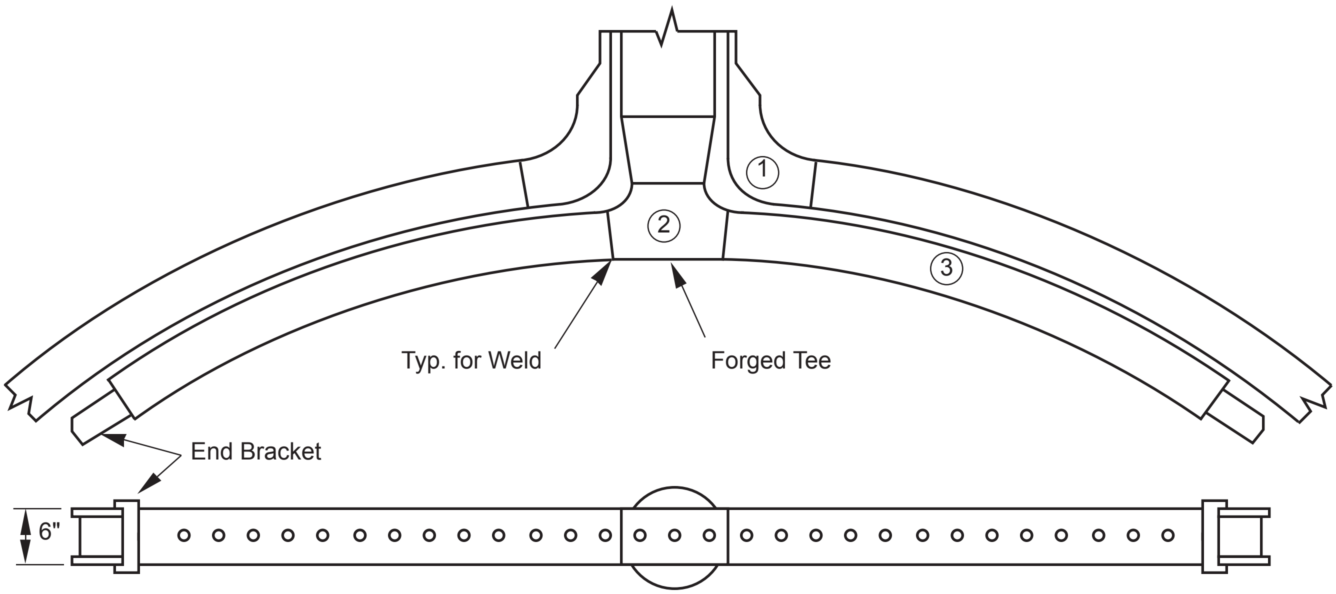
1 Nozzle, SA-508, Cl.II
2 Safe End, SB-166, Inconel
3 Thermal Sleeve Extension, SB-166
4 Thermal Sleeve, SA-336, Cl.F8
5 Inconel Overlay
6 Weld Illustration
7 Back-up Ring, SB-168

Columbia Generating Station
Final Safety Analysis Report

Feedwater Nozzle

Draw. No. 960690.56 | Rev. | Figure 5.3-6

Form No. 960690



1 Nozzle, SA-508, CI.II
2 Forged Tee, 304S.S
3 Sparger Header, 304S.S

Feedwater Sparger

Draw. No. 960690.57 | Rev. | Figure 5.3-7

5.4 COMPONENT AND SUBSYSTEM DESIGN

Pumps and valves within the reactor coolant pressure boundary (RCPB) are described in Table 5.4-1.

5.4.1 REACTOR RECIRCULATION PUMPS

5.4.1.1 Safety Design Bases

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

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

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

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

5.4.1.2 Power Generation Design Bases

The RRC meets the following power generation design bases:

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

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

5.4.1.3 Description

The RRC consists of the two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps (see Figure 5.4-1). Each external loop contains one high-capacity variable-speed motor-driven recirculation pump. The motor is powered by an adjustable speed drive (ASD). The external loop also contains two motor-operated gate valves (for pump maintenance). Each pump suction line contains a flow measuring system. The recirculation loops are part of the RCPB and are located inside the drywell structure. The jet pumps are reactor vessel internals. Their location and mechanical design are discussed in Section 3.9.5. The important design and performance characteristics of the RRC is shown in Table 5.4-2.

The head, flow, torque, net positive suction head (NPSH), BHP, and efficiency curves are shown in Figures 5.4-2, 5.4-3, and 5.4-4. Instrumentation and control description is provided in Sections 7.6 and 7.7.

The recirculation system piping and normally flooded section of the reactor vessel is periodically coated with a microscopic layer of noble metals. This coating serves to create a catalytic layering of the noble metal platinum to reduce the hydrogen addition injection rate required to achieve a low electrochemical corrosion potential (ECP). The low ECP achieves intergranular stress corrosion cracking (IGSCC) and irradiation assisted stress corrosion cracking (IASCC) protection while minimizing the effects of high dose rates attributed to regular hydrogen injection rates.

The recirculated coolant consists of saturated water from the steam separators and dryers that have been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus provides the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing suction (see Figure 5.4-5). The adequacy of the total flow to the core is discussed in Section 4.4.

The allowable heatup rate for the recirculation pump casing is the same as the reactor vessel. If one loop is shut down, the idle loop can be kept hot by leaving the loop valves open; this permits the reactor pressure plus the active jet pump head to cause reverse flow in the idle loop. When starting the pump in an idle recirculation loop with the other loop in operation, the operating loop flow will be verified to be less than 50% of rated loop flow within 15 minutes prior to pump start.

Because the removal of the reactor recirculation gate valve internals would require unloading the core, the objective of the valve trim design is to minimize the need for maintenance of the valve internals. The valves are provided with high quality backseats that permit renewal of stem packing while the system is full of water.

The 20-in. motor-operated gate valves provide pump and flow control valve (FCV) isolation during maintenance. The suction valve is capable of closing with up to 50 psi differential, while the discharge valve can close with up to 400 psi differential. Both valves are remote manually operated.

The FCV is blocked open (seized in the full open position). This condition does not affect the pressure integrity or impact the transient duty cycle of the valve or allow the ball to break away from the shaft.

The required NPSH for the recirculation pumps and jet pumps is supplied by the subcooling provided by the feedwater flow. Accurate temperature detectors are provided in the recirculation lines. Steam dome temperature is provided through pressure conversion. The difference between these two readings is a direct measurement of the subcooling. If the subcooling falls below the time-delayed setpoint 10.7°F, the ASD system is reduced to minimum frequency 15 Hz (25% pump speed) on both of the RRC loops. Each loop has independent instrumentation for cavitation protection.

When preparing for hydrostatic tests, the nuclear system temperature must be raised above the vessel nil ductility transition (NDT) temperature limit. The vessel is heated by core decay heat and/or by operating the recirculation pumps.

Connections to the piping on the suction and discharge sides of the pumps provide a means to flush and decontaminate the pump and adjacent piping. The piping low point drain, designed for the connection of temporary piping, is used during flushing or decontamination.

Each recirculation pump is driven by an adjustable speed motor and is equipped with a two-stage mechanical seal cartridge. Each of the two seals in the package is subject to one-half the total pressure being sealed. Each seal is structurally capable of sealing full pressure for limited periods of operation. The two seals can be replaced without removing the motor from the pump. The pump shaft passes through a breakdown bushing in the pump casing to reduce leakage in the event of a gross failure of both shaft seals. The cavity temperature and pressure drop across each individual seal can be monitored.

Each recirculation pump motor is a vertical, solid-shaft, totally enclosed, air-water-cooled, induction motor. The combined rotating inertias of the recirculation pump and motor provide a slow coastdown of flow following loss of ASD-supplied power to the drive motors so that they are adequately cooled during the transient. This inertia requirement is met without a flywheel.

The ASD can vary the discharge flow of the pump proportionally to a reactor operator remote manually adjusted demand signal. The RRC GE-FANUC digital control scheme is described in Sections 7.6 and 7.7. The recirculation loop flow rate can be varied, within the expected flow range, in response to changes to system demand.

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

The pump drive motor, impeller, and wear rings are designed for as long a life as is practical. Pump mechanical seal parts and the valve packing have life expectancies which afford convenient replacement during the refueling outages.

The ASD system selected to drive the recirculation pump induction motor is a dual channel system. Two ASDs are provided, capable of 11,200 hp at 66 Hz per RRC loop. If one channel fails, the RRC loop flow capability must be reduced to the capability of a single channel ASD. The dual channel ASD system provides for high availability of the ASD system. The ASD system is a solid-state frequency converter with overall high availability. Sections 7.6 and 7.7 provide more detail of the system design.

The recirculation system piping is designed and constructed to meet the requirements of the applicable ASME and ANSI codes.

The RRC pressure boundary equipment is designed as Seismic Category I equipment. The pump is assumed to be filled with water for the analysis. Snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

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

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

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

The residual heat removal (RHR) system can use the recirculation loop jet pumps to provide circulation through the reactor core. Operating restrictions limit RHR operation to regions where jet pump cavitation does not occur.

5.4.1.3.1 Recirculation System Cavitation Consideration

Cavitation Coefficients

The recirculation pump, jet pump, and FCV were tested to determine their cavitation coefficients so that prolonged operation in cavitating regimes can be avoided.

Equipment Damage Provisions

Cavitation interlocks are provided for the recirculation pump and jet pumps; since cavitation produces material damage after long-term operation and the damage potential decreases with an increase in water temperature, short periods of cavitation during a transient or accident are not a concern. However, long-term operation that might occur is of sufficient concern to call for inspections during the next refueling outage. Consequently, to avoid the need for such inspections, automatic interlocks are installed. Class 1E equipment is not necessary for power generation design requirements, so the automatic interlocks are non-Class 1E.

The consequences of cavitation would require inspection of the affected component and repair or replacement if the inspection showed unacceptable damage. Consequently, cavitation could call for increased scheduled outage time for inspection/repair affecting plant availability power generation design goals.

The ASD and its GE-FANUC digital control system is a non-safety-related system. The ASD and control system have alarm and protective systems and are provided with on-line video diagnostic displays at the main control room operating benchboard.

5.4.1.4 Safety Evaluation

Reactor recirculation system malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Section 15.3. It is shown in Section 15.3 that none of the malfunctions result in significant fuel damage. The RRC has sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients.

The core flooding capability of a jet pump design plant is discussed in detail in the emergency core cooling system (ECCS) document submitted to the NRC (Reference 5.4-1). The ability to reflood the boiling water reactor (BWR) core to the top of the jet pumps is shown schematically in Figure 5.4-6 and is discussed in Reference 5.4-1.

Piping and pump design pressures for the RRC are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest point in the recirculation loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria ensures that a system designed, built,

and operated within design limits has an extremely low probability of failure caused by any known failure mechanism.

Purchase specifications require that the recirculation pumps first critical speed shall not be less than 130% of operating speed. Calculation submittal was required and approved.

Purchase specifications require that integrity of the pump case be maintained through all transients and that the pump remain operable through all normal and upset transients. The design of the motor bearings are required to be such that dynamic load capability at rated operating conditions is not exceeded during the safe shutdown earthquake (SSE). Calculation submittal was required of the vendor and has been received and approved by GE.

Pump overspeed occurs during the course of a LOCA due to blowdown through the broken loop's pump. Design studies determined that the overspeed was not sufficient to cause destruction of the motor; consequently no pump overspeed protection provision was made.

A failure modes effects analysis (FMEA) was performed on the block valves. In addition, an analysis was made to determine the effect of block valve closure on recirculation pump coastdown. The analysis postulates that coincident with a recirculation pump trip, the block valves begin to close. It was concluded that any closure time greater than 1 minute will have no effect on coastdown times. The consequences of an inadvertent closure without a coincident pump trip is covered in the FMEA.

5.4.1.5 Inspection and Testing

Quality control methods were used during fabrication and assembly of the RRC to ensure that design specifications were met. Inspection and testing is carried out as described in Chapter 3. The reactor coolant system was thoroughly cleaned and flushed before fuel was loaded initially.

During the preoperational test program, the RRC was hydrostatically tested at 125% reactor vessel design pressure. Preoperational tests on the RRC also included checking operation of the pumps, flow control system, and gate valves, and are discussed in Chapter 14.

During the startup test program, horizontal and vertical motions of the RRC piping and equipment were observed as described in Section 5.4.14.

5.4.2 STEAM GENERATORS (Pressurized Water Reactor)

This is not applicable to BWR plants.

5.4.3 REACTOR COOLANT PIPING

The RCPB piping is discussed in Sections 3.9.3.1 and 5.4.1. The recirculation loops are shown in Figures 5.4-1 and 5.4-7. The design characteristics are presented in Table 5.4-2. Avoidance of stress corrosion cracking is discussed in Section 5.2.3.

5.4.4 MAIN STEAM LINE FLOW RESTRICTORS

5.4.4.1 Safety Design Bases

The main steam line flow restrictors were designed to

a. Limit the rate of vessel blowdown to 200 percent of the normal rated flow in the event of a steam line break outside containment. This limits the reactor depressurization rate to a value which will ensure that the steam dryer and other reactor internal structures remain in place.

b. Withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steam line,

c. Limit the amount of radiological release outside of the drywell prior to main steam isolation valve (MSIV) closure, and

d. Provide trip signals for MSIV closure.

5.4.4.2 Description

A main steam line flow restrictor (see Figure 5.4-8) is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line. It is located between the last main steam line safety/relief valve (SRV) and the inboard MSIV.

The restrictor limits the coolant blowdown rate from the reactor vessel in the event a main steam line break occurs outside the containment. The restrictor assembly consists of a venturi-type nozzle insert welded, in accordance with applicable code requirements, into the main steam line. The flow restrictor is designed and fabricated in accordance with the ASME "Fluid Meters," 6th edition, 1977.

The flow restrictor has no moving parts. Its mechanical structure can withstand the velocities and forces associated with a main steam line break. The maximum differential pressure is conservatively assumed to be 1375 psi, the reactor vessel ASME Code limit pressure.

The ratio of venturi throat diameter to steam line inside diameter of approximately 0.55 results in a maximum pressure differential (unrecovered pressure) of about 10 psig at 100% of rated

flow. This design limits the steam flow in a severed line to less than 200% rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the MSIVs when the steam flow exceeds preselected operational limits.

5.4.4.3 Safety Evaluation

A postulated guillotine break of one of the four main steam lines outside the containment results in mass loss from both ends of the break. The flow from the upstream side is initially limited by the flow restrictor upstream of the inboard isolation valve. Flow from the downstream side is initially limited by the total area of the flow restrictors in the three unbroken lines. Subsequent closure of the MSIVs further limits the flow when the valve area becomes less than the limiter area and finally terminates the mass loss when full closure is reached.

Analysis of the main steam break accident outside containment demonstrates that the radioactive materials released to the environs results in calculated doses that are in compliance with 10 CFR 50.67 and Regulatory Guide 1.183 dose limits.

Tests on a scale model determined final design and performance characteristics of the flow restrictor. The characteristics include maximum flow rate of the restrictor corresponding to the accident conditions, unrecoverable losses under normal plant operating conditions, and discharge moisture level. The tests showed that flow restriction at critical throat velocities is stable and predictable.

The steam flow restrictor is exposed to steam of 0.10% to 0.20% moisture flowing at velocities approximately 150 ft/sec (steam piping I.D.) to 600 ft/sec (steam restrictor throat). The cast austenitic stainless steel (ASME SA351, or ASTM A351, Type CF8) was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion in a high velocity steam atmosphere. The excellent performance of stainless steel in high velocity steam appears to be due to its resistance to corrosion. A protective surface film forms on the stainless steel which prevents any surface attack and this film is not removed by the steam.

Hardness has no significant effect on erosion-corrosion. For example, hardened carbon steel or alloy steel will erode rapidly in applications where soft stainless steel is unaffected.

Surface finish has a minor effect on erosion-corrosion. Experience shows that a machined or a ground surface is sufficiently smooth and that no detrimental erosion will occur.

5.4.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion will occur with

time, and such a slight enlargement will have no safety significance. Stainless steel resistance to corrosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which have revealed no noticeable effects from erosion on the stainless steel nozzle partitions. The Dresden inlet velocities are about 300 ft/sec and the exit velocities are 600 to 900 ft/sec. However, calculations show that, even if the erosion rates are as high as 0.004 in. per year, after 40 years of operation the increase in restrictor choked flow rate would not exceed 5%. The impact on calculated accident radiological releases would be minimal.

5.4.5 MAIN STEAM LINE ISOLATION SYSTEM

The MSIV leakage control system has been deactivated.

5.4.5.1 Safety Design Bases

The MSIVs, individually or collectively, shall

a. Close the main steam lines within the time established by design-basis accident analysis to limit the release of reactor coolant,

b. Close the main steam lines slowly enough that simultaneous closure of all steam lines will not induce transients that exceed the nuclear system design limits,

c. Close the main steam line when required despite single failure in either valve or in the associated controls, to provide a high level of reliability for the safety function,

d. Use separate energy sources as the motive force to close independently the redundant isolation valves in the individual steam lines,

e. Use local stored energy (compressed air and/or springs) to close at least one isolation valve in each steam pipe line without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure,

f. Have capability to close the steam lines, either during or after seismic loadings, to ensure isolation if the nuclear system is breached, and

g. Have capability for testing during normal operating conditions to demonstrate that the valves will function.

5.4.5.2 Description

Two isolation valves are welded in a horizontal run of each of the four main steam pipes; one valve is as close as possible to the inside of the drywell and the other is just outside the primary containment.

Figure 5.4-9 shows an MSIV. Each is a 26-in. Y-pattern, globe valve. Rated steam flow rate through each valve is 3.85 x 10^6 lb/hr. The main disc or poppet is attached to the lower end of the stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed. The bottom end of the valve stem closes a small pressure balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give flow areas past the wide open poppet approximately equal to the seat port area. The poppet travels approximately 90% of the valve stem travel to close the main disc and approximately the last 10% of travel to close the pilot hole. The air cylinder can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

A 45-degree angle permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at 105% of rated flow is 7 psi maximum. The valve stem penetrates the valve bonnet through a stuffing box that has Grafoil packing. To help prevent leakage through the stem packing, the poppet backseats when the valve is fully open.

Attached to the upper end of the stem is an air cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 and 10 sec.

The air cylinder is supported on the valve bonnet by actuator support and spring guide shafts. Helical springs around the spring guide shafts maintain the valve in the closed position if air pressure is not available.

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the air cylinder. This unit contains three types of control valves that open and close the main valve and exercise it at slow speed. Remote manual switches in the control room enable the operator to operate the valves.

Operating air is supplied to the outboard valves from the plant air system and to the inboard valves from the containment instrument system (nitrogen). An air accumulator between the control valve and a check valve provides backup operating air. The outboard MSIVs will close on spring force or air cylinder pressure; the inboard valves require spring force and air pressure to close.

Each valve is designed to accommodate saturated steam at plant operating conditions, with a moisture content of approximately 0.25%, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The valves are furnished in conformance with a design pressure and temperature rating in excess of plant operating conditions to accommodate plant overpressure conditions.

In the worst case if the main steam line should rupture downstream of the valve, steam flow would quickly increase to 200% of rated flow. Further increase is prevented by the venturi flow restrictor inside the containment.

During approximately the first 75% of closing, the valve has little effect on flow reduction because the flow is choked by the venturi restrictor. After the valve is approximately 75% closed, flow is reduced as a function of the valve area versus travel characteristic.

The design objective for the valve is a minimum of 40-years service at the specified operating conditions. Operating cycles (excluding routine exercise cycles) are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter.

In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.120-in. minimum is added to provide for 40 years of service.

Design specification ambient conditions for normal plant operation are 135°F normal temperature, 150°F maximum temperature, 100% humidity, in a radiation field of 15 rad/hr gamma and 25 rad/hr neutron plus gamma, continuous for design life. The inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions that are considerably less severe.

The MSIVs are designed to close under accident environmental conditions of 340°F for 1 hr at drywell design pressure. In addition, they are designed to remain closed under the following postaccident environment conditions:

a. 340°F for an additional 2 hr at drywell design pressure of 45 psig maximum,
b. 320°F for an additional 3 hr at 45 psig maximum,
c. 250°F for an additional 24 hr at 25 psig maximum, and
d. 200°F during the next 100 days at 20 psig maximum.

To resist sufficiently the response motion from the SSE, the main steam line valve installations are designed as Seismic Category I equipment. The valve assembly is manufactured to withstand the SSE forces applied at the mass center of the extended mass of the valve operator, assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously. The stresses in the actuator supports caused by

seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on the allowable stress set forth in applicable codes. The parts of the MSIVs that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Code Section III.

5.4.5.3 Safety Evaluation

The analysis of a complete, sudden steam line break outside the containment is described in Chapter 15, "Accident Analyses." The shortest closing time (approximately 3 sec) of the MSIVs is also shown in Chapter 15, to be satisfactory. The switches on the valves initiate reactor scram when specific conditions (extent of valve closure, number of pipe lines included, and reactor power level) are exceeded (see Section 7.2.1.1).

The ability of this 45-degree, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full-size, 20-in. valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions (Reference 5.4-2).

The following specified hydrostatic, leakage, and stroking tests, as a minimum, were performed by the valve manufacturer in shop tests:

a. To verify valve capability to close at settings between 3 and 10 sec,[*] each valve was tested at rated pressure (1000 psig) and no flow. The valve was stroked several times, and the closing time recorded. The valve was closed by spring only and by the combination of air cylinder and springs. The closing time is slightly greater when closure is by springs only;

b. Leakage was measured with the valve seated and backseated. The specified maximum seat leakage, using cold water at design pressure, was 2 cm^3/hr/in. of nominal valve size. In addition, an air seat leakage test was conducted using 50 psi pressure upstream. Maximum permissible leakage was 0.1 scfh/in. of nominal valve size. There was no visible leakage from the stem packing at hydrostatic test pressure. The valve stem was operated a minimum of three times from the closed position to the open position, and the packing leakage was zero by visual examination;

[*] Response time for full closure is set prior to plant operation for 3 sec minimum, 5 sec maximum.

c. Each valve was hydrostatically tested in accordance with the requirements of the applicable edition and addenda of the ASME Code. During valve fabrication, extensive nondestructive tests and examinations were conducted. Tests included radiographic, liquid penetrant, or magnetic particle examinations of castings, forgings, welds, hardfacings, and bolts; and

d. The spring guides and guiding of the spring seat member on support shafts and rigid attachment of the seat member ensure correct alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying stem force near the bottom of the poppet.

After the valves were installed in the nuclear system, each valve was tested as discussed in Chapter 14.

Two isolation valves provide redundancy in each steam line so either can perform the isolation function, and either can be tested for leakage after the other is closed. The inside valve, the outside valve, and their respective control systems are separated physically.

Electrical equipment that is associated with the isolation valves and operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The expected pressure and temperature transients following an accident are discussed in Chapter 15.

5.4.5.4 Inspection and Testing

The MSIVs can be functionally tested for operability during plant operation and refueling outage. The test provisions are listed below. During refueling outage the MSIVs can be functionally tested, leak tested, and visually inspected.

The MSIVs can be tested and exercised individually to the 90% open position, because the valves still pass rated steam flow when 90% open.

The MSIVs can also be tested and exercised individually to the fully closed position if reactor power is reduced sufficiently to avoid scram from reactor overpressure or high flow through the steam line flow restrictors.

Leakage from the valve stem packing will become suspect during reactor operation from measurements of leakage into the drywell, or from observation or similar measurements in the steam tunnel.

The leak rate through the pipe line valve seats (pilot and poppet seats) can be measured accurately during shutdown by the procedure described in the following:

a. With the reactor at approximately 125°F and normal water level and decay heat being removed by the RHR system in the shutdown cooling mode, all MSIVs are closed utilizing both spring force and air pressure on the operating cylinder;

b. Air from the instrument air system is introduced between the isolation valves at 25 to 26 psig. A pressure decay test or an air makeup test is used to determine combined inboard and outboard isolation valve seat leakage;

c. If combined inboard and outboard isolation valve seat leakage is above the allowed leakage for a single isolation valve, the outboard isolation valve is then tested for seat leakage;

d. To leak-test the outboard isolation valves, the reactor vessel side of the inboard valves is pressurized to approximately the same pressure as the test pressure between the inboard and outboard valves using nitrogen gas or a hydrostatic head. A pressure decay or makeup leak test is then performed on the area between the isolation valves. This ensures essentially zero leakage through the inboard valves with test results indicating outboard valve seat leakage. The volume between the closed valves is accurately known. Corrections for temperature variation during the test period are made to obtain the required accuracy; and

e. At each refueling outage, the MSIVs are slow closed to verify the stem packing is not too tight. Also, the inboard MSIV containment instrument air (CIA) supply pressure boundary from the accumulator check valve to the actuator is verified to not exceed the allowable leak rate.

Such a test and leakage measurement program ensure that the valves are operating correctly and that any leakage trend is detected.

During prestartup tests following an extensive shutdown, the valves will receive the same pressure boundary leakage or hydro tests (approximately 1000 psi) that are imposed in the primary system.

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

5.4.6.1 Design Bases

The reactor core isolation cooling (RCIC) system initiates the discharge of a specified constant flow into the reactor vessel over a specified pressure range within a 30-sec time interval. The RCIC water discharge into the reactor vessel varies between a temperature of 40°F up to and

including a temperature of 140°F. The mixture of the RCIC water and the hot steam does the following:

a. Quenches the steam,

b. Removes reactor residual heat by reducing the heat level (enthalpy) due to the temperature differential between the steam and water, and

c. Replenishes reactor vessel inventory.

The RCIC system uses an electrical power source of high reliability, which permits operation with either onsite power or offsite power.

The steam supply to the RCIC turbine is automatically isolated on detection of abnormal conditions in the RCIC system or in RCIC equipment areas. See Section 7.4.1.1.2.

The RCIC system is neither an ECCS nor an engineered safety feature (ESF) system; however, it is included in these sections because of its similar functions. No credit (simulation) is taken in the accident analysis of Chapter 6 or 15 for its operation. However, the system is designed to initiate during plant transients that cause low reactor water level. The design bases with respect to General Design Criteria 34, 55, 56, and 57 are provided in Chapter 3. Reactor core isolation cooling containment isolation valve arrangements are described in Section 6.2.

The RCIC system as noted in Table 3.2-1 is designed commensurate with the safety importance of the system and its equipment. Each component was individually tested to confirm compliance with system requirements. The system as a whole was tested during both the startup and preoperational phases of the plant to set a base mark for system reliability. To confirm that the system maintains this mark, functional and operability testing is performed at predetermined intervals throughout the life of the plant.

In addition to the automatic operational features, provisions have been included for remote-manual startup, operation, and shutdown of the RCIC system, provided initiation or shutdown signals have not been actuated for startup and operation.

The RCIC system is physically located in a different quadrant of the reactor building and uses different divisional power (and separate electrical routings) than the HPCS system. The system operates for the time intervals and the environmental conditions specified in Section 3.11.

5.4.6.2 System Design

5.4.6.2.1 General

5.4.6.2.1.1 Description. The RCIC system consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to ensure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling. This prevents reactor fuel overheating should the vessel be isolated and accompanied by loss-of-coolant flow from the reactor feedwater system.

Following a reactor shutdown, steam generation will continue at a reduced rate due to the core fission product decay heat. At this time the turbine bypass system will divert the steam to the main condenser, and the feedwater system will supply the makeup water required to maintain reactor vessel inventory.

In the event the reactor vessel is isolated and the feedwater supply is unavailable, relief valves are provided to automatically (or remote manually) maintain vessel pressure within desirable limits. The water level in the reactor vessel will drop due to continued steam generation by decay heat.

On reaching a predetermined low level, the RCIC system is initiated automatically. The RCIC turbine is driven with a portion of the decay heat steam from the reactor and exhausts to the suppression pool. The turbine-driven pump takes suction from the condensate storage tank (CST) during normal modes of operation and injects into the reactor vessel. Condensate storage tank freeze protection is discussed in Section 9.2.6. Since the CST is a covered tank, the water supply is not affected by dust storms. If the water supply from the CST becomes exhausted there is an automatic switchover to the suppression pool as the water source for the RCIC pump. This automatic switchover feature for RCIC consists of two Class 1E level switches mounted on a standpipe in the pump suction line. This standpipe is located on the condensate supply line inside the reactor building at the reactor building/service building interface.

The standpipe is open ended and is used to indicate either a low water level condition in the CST or a loss-of-suction supply from the CST. The standpipe is designed, fabricated, and installed to Seismic Category I, Quality Class I, and ASME Section III, Class 2 standards.

The piping from the reactor building/service building interface to the RCIC system is Seismic Category I; each circumferential buttweld has been radiographically examined per ASME Section III, NC-5230, and a chemical analysis has been performed on all piping materials and as-deposited weld materials.

The inline suction reserve from the CST has sufficient volume to maintain the minimum required NPSH for the RCIC pump plus an approximate four-ft margin while the switchover

occurs, thus ensuring a water supply for continuous operation of the RCIC system. The CST switchover level of 448 ft 3 in. provides an additional submergence of 2 ft (above the top of the CST outlet pipe), which is more than adequate to preclude vortex formation in the CST since less than 6 in. of additional submergence for vortex prevention is required for RCIC.

The available NPSH for worst-case operating conditions (i.e., 625 gpm rated flow, maximum water temperature) was calculated for the RCIC pump suction from the suppression pool and the CST. Using the conservative water temperature of 140°F, the NPSH available from the suppression pool is approximately 60 ft. For the CST, using 100°F water, the NPSH available is 48 ft. In both cases, the NPSH available is greater than the required NPSH of 20 ft indicated in Figure 5.4-10 for the RCIC turbine high speed setpoint of 4500 rpm.

The RCIC suction line from the suppression pool has also been evaluated for vortex formation. The RCIC system has adequate NPSH and will not vortex under the conditions it would be expected to operate.

During RCIC operation, the suppression pool acts as the heat sink for steam generated by reactor decay heat. This will result in a rise in pool water temperature. Heat exchangers in the RHR system are used to maintain pool water temperature within acceptable limits by cooling the pool water directly.

The RCIC turbine discharges into a 10-in. exhaust pipe (see Figure 5.4-11), which has been installed as a sparger to prevent flow-induced oscillations due to steam bubble formation and collapse in the suppression pool. Also, a vacuum breaker system has been installed close to the RCIC turbine exhaust line suppression pool penetration to avoid siphoning water from the suppression pool into the exhaust line as steam in the line condenses during and after turbine operation. The vacuum breaker line runs from the suppression pool air volume to the RCIC exhaust line through two normally open motor-operated gate valves and two swing check valves arranged to allow air flow into the exhaust line and to preclude steam flow to the suppression pool air volume. Condensate buildup in the turbine exhaust line is removed by a drain pot in the low point of the line near the turbine exhaust connection. The condensate collected in the drain pot drains to the barometric condenser.

5.4.6.2.1.2 Diagrams. The following diagrams are included for the RCIC systems:

a. A schematic "Piping and Instrumentation Diagram" (Figures 5.4-11) shows all components, piping, points where interface system and subsystems tie together and instrumentation and controls associated with subsystem and component actuation,

b. A schematic "Process Diagram" (Figure 5.4-12) shows temperature, pressures, and flows for RCIC operation and system process data hydraulic requirements, and

c. RCIC turbine and pump performance curves; Constant Pump Flow Figure 5.4-10 and Constant Pump Speed Figure 5.4-13.

5.4.6.2.1.3 Interlocks. The following defines the various electrical interlocks:

a. There are four key-locked valves, RCIC-V-63 (F063), RCIC-V-8 (F008), RCIC-V-68 (F068), and RCIC-V-69 (F069), and two key-locked resets, the "isolation resets;"

b. RCIC-V-31 (F031) limit switch activates when fully open and closes RCIC-V-10 (F010), RCIC-V-22 (F022), and RCIC-V-59 (F059);

c. RCIC-V-68 (F068) limit switch activates when fully open and clears RCIC-V-45 (F045) permissive so RCIC-V-45 (F045) can open;

d. RCIC-V-45 (F045) limit switch activates when RCIC-V-45 (F045) is not fully closed and energizes 15-sec time delay for low pump suction pressure trip and also initiates startup ramp function. This ramp resets each time RCIC-V-45 (F045) is closed;

e. RCIC-V-45 (F045) limits switch activates when fully closed and permits RCIC-V-4 (F004), RCIC-V-5 (F005), RCIC-V-25 (F025), and RCIC-V-26 (F026) to open and closes RCIC-V-13 (F013), RCIC-V-46 (F046) and RCIC-V-19 (F019). RCIC-V-13 (F013) and RCIC-V-46 (F046) auto open on initiation signal if RCIC-V-45 (F045) and RCIC-V-1 (F001) are open;

f. The turbine trip throttle valve RCIC-V-1 limit switch activates when fully closed and closes RCIC-V-13 (F013), RCIC-V-46 (F046) and RCIC-V-19 (F019);

g. The combined pressure switches at reactor low pressure and high drywell pressure when activated closes RCIC-V-110 and 113 (F080 and F086);

h. RCIC high turbine exhaust pressure, low pump suction pressure, low discharge header pressure, or an isolation signal actuates and closes the turbine trip throttle valve. When signal is cleared, the trip throttle valve must be reset from control room;

i. 125% overspeed trips both the mechanical trip at the turbine and the trip throttle valve. The former is reset at the turbine and then the later is reset in the control room;

j. Valves RCIC-V-8 (F008), RCIC-V-63 (F063), and RCIC-V-76 (F076) automatically isolate on low reactor pressure, high turbine exhaust line pressure, high ambient temperature in RCIC equipment areas (leak detection) and high turbine steam supply flow rate (>300% - break detection). A setpoint of 300% for break isolation provides sufficient operating margin to prevent inadvertent isolations due to startup transients and yet is low enough to detect large pipe breaks. Small breaks are detected by the leak detection system. Steam condensing supply valve RCIC-V-64 (F064) has been lock closed as a part of the steam condensing mode deactivation. Note, the key-locked switches for RCIC-V-8 (F008) and RCIC-V-63 (F063) do not prevent automatic isolation of these valves. The key-locked switches are provided to prevent inadvertent manual isolation of the RCIC steam supply during system operation;

k. An initiation signal opens RCIC-V-10 (F010) if closed, RCIC-V-45 (F045), and RCIC-V-46 (F046) if RCIC-V-1 and RCIC-V-45 (F045) are not closed. The initiation signal also starts barometric condenser vacuum pump; and closes RCIC-V-22 (F022) and RCIC-V-59 (F059) if open;

l. The combined signal of low flow plus high discharge pressure opens and with increased flow closes RCIC-V-19 (F019). Also see items e and f above;

m. The signal of in-line reserve tank low water level opens valve RCIC-V-31 (F031);

n. High reactor water level closes RCIC-V-45 (F045); and

o. Main turbine trips if RCIC-V-13 and RCIC-V-45 are open.

5.4.6.2.2 Equipment and Component Description

5.4.6.2.2.1 <u>Design Conditions</u>. Operating parameters for the components of the RCIC systems defined in the following are shown in Figure 5.4-12.

a. One 100% capacity turbine and accessories,

b. One 100% capacity pump assembly and accessories, and

c. Piping, valves, and instrumentation for

   1. Steam supply to the turbine,

   2. Turbine exhaust to the suppression pool,

3. Makeup supply from the CST to the pump suction,

4. Makeup supply from the suppression pool to the pump suction, and

5. Pump discharge to the head cooling spray nozzle, including a test line to the CST, a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment.

5.4.6.2.2.2 Design Parameters. Design parameter for the RCIC system components are listed below. See Figure 5.4-11 for cross reference of component numbers listed below:

a. RCIC pump operation RCIC-P-1 (C001) (Reference to Figures 5.4-11 and 5.4-13)

Flow rate	Injection flow - 600 gpm Lube oil cooling water flow - 16-25 gpm Total pump discharge - 625 gpm (includes no margin for pump wear)
Water temperature range	40°F to 140°F
NPSH	21 ft minimum
Developed head	3016 ft @ 1225 psia reactor pressure 610 ft @ 165 psia reactor pressure
BHP, not to exceed	761 HP @ 3016 ft developed head 130 HP @ 610 ft developed head
Design pressure	1500 psia
Design temperature	40°F to 140°F

b.

RCIC turbine operation RCIC-DT-1 (C002)	HP condition	LP condition
Reactor pressure (saturation temperature)	1225 psia	165 psia
Steam inlet pressure	1210 psia	150 psia
Turbine exhaust press	15 to 25 psia	15 to 25 psia
Design inlet pressure	1265 psia + saturated temperature	
Design exhaust pressure	165 psia + saturated temperature	

c. RCIC orifice sizing

Coolant loop orifice RCIC-RO-9 (D009)	Sized with piping arrangement to ensure maximum pressure of 75 psia at the lube oil cooler inlet and a minimum pressure of 45 psia at the spray nozzles at the barometric condenser
Minimum flow orifice RCIC-RO-5 (D005)	Sized with piping arrangement to ensure minimum flow of 100 gpm with RCIC-V-19 (MO-F019) fully open
Test return orifice RCIC-RO-6 (D006)	Sized with piping arrangement to simulate pump discharge pressure required when the RCIC system is injecting design flow with the reactor vessel pressure at 165 psia
Leak-off orifices RCIC-RO-8 and RCIC-RO-10 (D008 and D010)	Sized for 1/8-in. diameter minimum, 3/16-in. diameter maximum
Minimum flow orifice RCIC-RO-11 (D011)	Sized to maintain a minimum flow of 60 gpm through the RCIC water leg pump (RCIC-P-3) while maintaining a positive pressure in the RCIC system at the highest elevation

d. Valve operation requirements

NOTE: Differential pressures listed in the following were obtained from the RCIC system design specification data sheet and are listed for information. Detailed differential pressure requirements are contained in engineering calculations.

Steam supply valve RCIC-V-45 (F045)	Open and/or close against full steam pressure
Pump discharge valve RCIC-V-13 (F013)	Open and/or close against full pump discharge pressure and open in thermal over-pressure conditions in the RCIC discharge header

Pump minimum flow bypass valve RCIC-V-19 (F019)	Open and/or close against full pump discharge pressure
Steam supply isolation valves RCIC-V-08/RCIC-V-63 (F008)	Open and/or close against full differential pressure of 1210 psi
Turbine lube oil/cooling water pressure control valve RCIC-PCV-15 (F015)	Capable of maintaining constant downstream pressure of 75 psia through lube oil cooler
Pump discharge header relief valve (RCIC-RV-3)	1500 psig relief setting; less than 1 gpm required capacity; the maximum allowable discharge is less than 20 gpm
Pump suction relief valve RCIC-RV-17 (F017)	122 psig relief setting; 20 gpm required capacity
Cooling water relief valve (RCIC-RV-19T)	Sized to prevent overpressurization of piping valves and equipment in the turbine lube oil coolant loop in the event of failure of pressure control valve RCIC-PCV-15 (F015). Set pressure is 99 psig; required flow is 33.1 gpm
Pump test return valve RCIC-V-22 (F022)	Qualified to open, close, and throttle against full pump discharge pressure
Pump test return valve RCIC-V-59 (F059)	Qualified to close (not open) against full pump discharge pressure
Relief valve barometric condenser vacuum tank RCIC-RV-33 (F033)	Relief valve is capable of retaining 10 in. of mercury vacuum at 140°F ambient, with a set pressure of 6 psig; required flow is 20 gpm
Pump suction valve suppression pool RCIC-V-31 (F031)	Located as close as practical to the primary containment
Pump suction valve condensate storage tank RCIC-V-10 (F010)	Open and/or close against full suction head from the condensate storage tank

Main pump discharge check valve RCIC-V-65/RCIC-V-66 (F065/F066)	System test mode bypasses this valve. Its functional capability is demonstrated separately
Warm-up line isolation valve RCIC-V-76 (F076)	Valve will open and/or close against full steam pressure
Vacuum breaker isolation valves RCIC-V-110 (F080) and RCIC-V-113 (F086)	Valves will open and/or close against turbine exhaust pressure

e. Rupture disc

Assemblies RCIC-RD-1/RCIC-RD-2 (D001/D002)	Utilized for turbine casing protection, includes a mated vacuum support to prevent rupture disc reversing under vacuum conditions Rupture pressure 150 psig ± 10 psig Flow capacity 60,000 lb/hr @ 165 psig

f. Condensate storage requirements

Total reserve storage for reactor pressure valve makeup is 135,000 gal.

g. Piping RCIC water temperature

The maximum water temperature range for continuous system operation will not exceed 140°F. However, due to potential short-term operation at higher temperatures, piping design is based on 170°F.

h. Turbine exhaust vertical reaction force

Unbalanced pressure due to opening and discharge under the suppression pool water level is 20 psi.

i. Ambient conditions

	Temperature	Relative Humidity
Normal plant operations	60°F to 100°F	95%
Isolation conditions	148°F	100%

j. Water leg pump

Design pressure	150 psig
Design temperature	212°F
Capacity	25 gpm @ 200 ft total head

k. Barometric condenser

Design pressure	50 psig
Design temperature	650°F

l. Vacuum tank

Design pressure	15 psig
Design temperature	212°F

m. Condensate pump

Design pressure	50 psig
Design temperature	650°F
Capacity	23 gpm @ 10 in. Hg vac., 70°F 50 psig discharge

n. Turbine and steam supply drain pots

Design pressure	1250 psig
Design temperature	575°F

o. Turbine governing and trip throttle valves

Design pressure	1250 psig
Design temperature	575°F

p. Pump suction strainers in the suction pool

The suction strainers have been procured to the following specifications:

Primary service rating: ANSI 1501-1

Quality Class I

Seismic Category I

Cleanliness Class B

Applicable Code:	Strainer materials and fabrication meets ASME Section III, Class 2 requirements. The "N" stamp is not be applied since the strainers cannot be hydrostatically tested.
Materials:	Strainer body is stainless steel 304 or 316, or engineer approved equal, suitable for submergence in high quality water during a 40-year lifetime.
Quantity:	2
Diameter:	13.5 in.
Length:	5.25 in.
Rated flow:	300 gpm (per strainer)

The strainers are cylindrical, as shown in Figure 5.4-14. Strainer hole diameter is 0.09375 in. Strainers are attached to ANSI 150# RF Flanges.

Head loss is limited to 4 ft of water assuming the strainers are 50% clogged and the water temperature is 220°F.

5.4.6.2.2.3 Overpressure Protection. Referring to Figure 5.4-11, four RCIC pipe lines have a low design pressure and, therefore, require relief devices or some other basis for addressing overpressure protection.

The design pressure of the other major pipe lines is equal to the vessel design pressure and subject to the normal overpressure protection system. In addition, the RCIC discharge header

has a relief valve, RCIC-RV-3, to protect against thermal overpressurization when the system is in standby mode, isolated from the reactor.

Below are the overpressure protection bases for the low pressure piping lines.

a. RCIC pump suction line

A relief valve [RCIC-RV-17 (F017)] is located on the pump suction line in Figure 5.4-11 to accommodate any potential leakage through the isolation valves [RCIC-V-13 (F013) and RCIC-V-66 (F066)]. A high pump suction pressure alarm is provided in the control room.

b. RCIC turbine exhaust line

This line is normally vented to the suppression pool and is not subject to reactor pressure during normal operation. Rupture discs RCIC-RD-1 (D001) and RCIC-RD-2 (D002), as shown in Figure 5.4-11, are installed on this line to prevent exceeding piping design pressure should the exhaust line isolation valve RCIC-V-68 (F068) be closed when the RCIC turbine is operating. The RCIC system will automatically isolate if the rupture discs were to blow open.

c. Portions of the RCIC minimum flow line downstream of RCIC-V-19 (F019)

This line is normally vented to the suppression pool and is separated from reactor pressure by the pump discharge isolation valves [RCIC-V-13, RCIC-V-65, and RCIC-V-66 (F013, F065, and F066)], pump discharge check valve RCIC-V-90, and one additional normally closed isolation valve in the minimum flow line [RCIC-V-19 (F019)] as shown in Figure 5.4-11.

d. Portions of the RCIC cooling water line downstream of RCIC-PCV-15 (F015)

In the standby condition this line is separated from reactor pressure by the pump discharge valves [RCIC-V-13, RCIC-V-65, and RCIC-V-66 (F013, F065 and F066)], pump discharge check valve RCIC-V-90, and one additional normally closed shut-off valve in the cooling water line [RCIC-V-46 (F046)] as shown in Figure 5.4-11. During system operation a relief valve [RCIC-RV-19T (F018)] is provided to prevent overpressurizing piping, valves, and equipment in the coolant loop in the event of failure of pressure control valve RCIC-PCV-15 (F015) as shown in Figure 5.4-11.

5.4.6.2.3 Applicable Codes and Classifications

The RCIC system components within the drywell up to and including the outer isolation valve are designed in accordance with ASME Code Section III, Class 1, Nuclear Power Plant Components. Safety-related portions of the RCIC system are Seismic Category 1.

The RCIC system component classifications and those for the condensate storage system are given in Table 3.2-1.

5.4.6.2.4 System Reliability Considerations

To ensure that the RCIC will operate when necessary, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given by the capability for periodic testing during station operation. Evaluation of reliability of the instrumentation for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system.

To ensure RCIC availability for the operational events noted previously, the following are considered in the system design.

a. The RCIC and HPCS are located in different quadrants of the reactor building. Piping runs are separated and the water delivered from each system enters the reactor vessel via different nozzles.

b. Prime mover independence is achieved by using a steam turbine to drive the RCIC and an electric motor-driven pump for the HPCS system.

c. The RCIC and HPCS control independence is secured by using different battery systems to provide control power to each system for system operation. Separate detection initiation logic is used for each system.

d. Both systems are designed to meet appropriate safety and quality class requirements. Environment in the equipment rooms is maintained by separate auxiliary systems.

e. A design flow functional test of the RCIC is performed during plant operation by taking suction from the CST and discharging through the full flow test return line back to the CST. The discharge valve to the head-spray line remains closed during the test, and reactor operation is undisturbed. All components of the RCIC system are capable of individual functional testing during normal plant operation. Control system design provides automatic return from test to operating mode if system initiation is required. The three exceptions are as follows:

1. The auto/manual station on the flow controller. This feature is required for operator flexibility during system operation.

2. Steam inboard/outboard isolation valves. Closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

3. Bypassed or other deliberately rendered inoperable parts of the system are automatically indicated in the control room.

f. Periodic inspections and maintenance of the turbine-pump unit are conducted in accordance with manufacturer's instructions. Valve position indication and instrumentation alarms are displayed in the control room.

g. Specific operating procedures relieve the possibility of thermal shock or water hammer to the steam line, valve seals, and discs. Key lock switches are provided for positive administrative control of valve position. Operating procedures require throttling open the outboard isolation valve RCIC-V-8 to remove any condensate trapped between the isolation valves, warming up the steam line by throttling open the warmup valve RCIC-V-76 located on a pipe line bypassing the inboard isolation valve, and then opening the inboard isolation valve RCIC-V-63. All the condensate is removed from the steam supply line by a drain pot located at the lowest point. An alarm sounds when any of these valves leaves the fully open position.

h. Emergency procedures address the operation of RCIC during a station blackout (SBO) event. The RCIC keepfill pump, RCIC-P-3, is powered by a Class 1E ac source, and will be unavailable during an SBO. Upon loss of ac power, the operator manually initiates RCIC. RCIC may be used during an SBO event by maintaining the RCIC discharge header continuously pressurized. The system can be operated in this manner without its keepfill function.

5.4.6.2.5 System Operation

5.4.6.2.5.1 Automatic Operation. Automatic startup or restart (after level 8 shutdown) of the RCIC system due to an initiation signal from reactor low water level requires no operator action. To permit this automatic operation, Technical Specifications operability requirements ensure that all necessary components are available to perform their required functions. In addition, the following are periodically verified:

a. The flow controller has the correct flow setpoint and is in automatic mode;

b. Each RCIC manual, power-operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position; and

c. The RCIC system piping is filled with water from the pump discharge valve to the injection valve.

The turbine is equipped with a mechanical overspeed trip. The mechanical overspeed trip must be reset out of the control room at the turbine itself. Once the mechanical overspeed trip is reset, the trip throttle valve can be reset.

RCIC System Operation and Shutdown:

During extended periods of operation and when the normal water level is again reached, the HPCS system may be manually tripped and the RCIC system flow controller may be adjusted and switched to manual operation. This prevents unnecessary cycling of the two systems. The RCIC flow to the vessel is controlled by adjusting flow to the amount necessary to maintain vessel level. Subsequent starts of RCIC will occur automatically if the water level decreases to the low level initiation point (Level 2) following a high level shutdown (Level 8). Should RCIC flow be inadequate, HPCS flow will automatically initiate.

RCIC flow may be directed away from the vessel by diverting the pump discharge to the CST. This is accomplished by closing injection valve RCIC-V-13 and opening the test return valves (RCIC-V-22 and 59). The system is returned to injection mode by closing RCIC-V-59 or RCIC-V-22 and then opening RCIC-V-13. This mode of operation will not be used during events where an unacceptable source term is identified in primary containment. Diverting RCIC flow to the CST is not a safety-related function nor does it affect the ability of RCIC to initiate during plant transients. The system automatically switches to injection mode if the water level decreases to the low level initiation point (Level 2).

When RCIC operation is no longer required, the RCIC system is manually tripped and returned to standby conditions.

5.4.6.2.5.2 Test Loop Operation. This operating mode (described in Section 5.4.6.2.4) is conducted by manual operation of the system.

5.4.6.2.5.3 Steam Condensing (Hot Standby) Operation. The steam condensing mode of RHR for Columbia Generating Station has been deactivated. However, the major pieces of equipment are installed with the exception of the steam supply relief valves and are shown on the RCIC and RHR piping and instrumentation diagrams (P&IDs) (Figures 5.4-11 and 5.4-15, respectively). Deletion of this mode of operation for RCIC and RHR will not adversely affect either system's capability to bring the reactor to cold shutdown.

5.4.6.2.5.4 Manual Actions. The RCIC system will automatically initiate and inject into the reactor when the reactor water level drops to a low level (L2, -50 in.). No manual actions are required to operate the system. However, control room operators can manually initiate the system prior to reaching the low level.

5.4.6.2.5.5 Reactor Core Isolation Cooling Discharge Line Fill System. See Section 6.3.2.2.5. The description in this section is also applicable to the RCIC line fill system.

5.4.6.3 Performance Evaluation

The RCIC system makeup capacity is sufficient to avoid the need for ECCS for normal shutdowns and shutdowns resulting from anticipated operational occurrences.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Chapter 14. Regulatory Guide 1.68 compliance is described in Section 1.8.

5.4.6.5 Safety Interfaces

The balance-of-plant/GE nuclear steam supply system safety interfaces for the RCIC system are (a) preferred water supply from the CST, (b) all associated wire, cable, piping, sensors, and valves that lie outside the nuclear steam supply system scope of supply, and (c) air supply for testable check and solenoid-actuated valve(s).

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

The RHR system is comprised of three independent loops. Each loop contains its own motor-driven pump, piping, valves, instrumentation, and controls. Each loop has a suction source from the suppression pool and is capable of discharging water to the reactor vessel via a separate nozzle, or back to the suppression pool via a separate suppression pool return line. In addition, the A and B loops have heat exchangers which are cooled by standby service water. Loops A and B can also take suction from the RRC suction and can discharge into the reactor recirculation discharge or to the suppression pool and drywell spray spargers. Spool-piece interties are available to permit the RHR heat exchangers to be used to supplement the cooling capacity of the fuel pool cooling (FPC) system (see Section 9.1.3 for details). A spool piece intertie was also used to provide a preoperational flushing path for the low-pressure core spray (LPCS). The A and B loops also have connections to the RCIC steam line. However, these are not used because the steam condensing mode has been eliminated.

5.4.7.1.1 Functional Design Basis

The RHR system is designed to restore and maintain the coolant inventory in the reactor vessel and to provide primary system decay heat removal following reactor shutdown for both normal and postaccident conditions. The primary design operating modes associated with performing these functions are briefly described as follows:

a. Low-pressure coolant injection (LPCI) mode - The RHR system automatically initiates into this mode and pumps suppression pool water into separate lines and core flooder nozzles for injection into the core region of the reactor vessel following a LOCA. The system's LPCI mode operates in conjunction with the other ECCS to provide adequate core cooling for all design basis LOCA conditions.

   The functional design bases for the LPCI mode is to pump a total of 7450 gpm of water per loop using the separate pump loops from the suppression pool into the core region of the vessel when there is a 26 psi differential between reactor pressure and the pressure of the suppression pool air volume. Injection flow commences at 225 psid vessel pressure above drywell pressure.

   The initiating signals are vessel level 1, 32 in. above the active core or drywell pressure equal to 2.0 psig. The pumps will attain rated speed in 27 sec and injection valves fully open in 46 sec.

   These original LPCI mode performance capabilities bound the power uprate conditions and ensure adequate core cooling can be provided following a LOCA at uprated power conditions;

b. Suppression pool cooling (SPC) and containment spray cooling (CSC) modes - The RHR system's SPC and CSC modes provide heat removal from the suppression pool and containment by pumping suppression pool water through the system's heat exchangers and discharging the water either directly back to the suppression pool (i.e., in the SPC mode) or discharging the water to the wetwell and drywell spray spargers (i.e., in the CSC mode) where the water is then returned, by drainage, back to the suppression pool. These modes of operation are designed to provide cooling to maintain containment and suppression pool temperatures and pressures following major transients. Suppression pool cooling is manually initiated by the operator; however, at least one RHR loop is placed in the SPC mode to maintain suppression pool temperature $\leq$110°F. The drywell spray function removes radioactive fission products from the containment atmosphere during a LOCA and is manually initiated within 15 minutes after the event occurs;

c. Shutdown cooling mode - The RHR system's normal shutdown cooling mode removes reactor core decay and sensible heat from the primary reactor system to permit refueling and servicing. This heat removal function is initiated manually after the reactor pressure has been reduced to less than 48 psig (295°F) by discharge of steam to the main condenser. This mode of operation provides the capability to cool down the reactor under controlled conditions with minimal availability impact. Refer to Section 5.4.7.3.1 for shutdown cooling time to reach 212°F;

d. Alternate shutdown cooling mode - The RHR system's alternate shutdown cooling mode is utilized during normal plant operation and design basis events when the normal shutdown cooling mode is not available to remove reactor core decay and sensible heat. This heat removal function is safety related, initiated manually and pumps suppression pool water into the core and allows the water to return to the suppression pool through the SRVs. The design objective of this mode (as established by Regulatory Guide 1.139) is to reach cold shutdown within 36 hrs and to meet the requirements of GDC 34;

e. Fuel pool cooling mode - During normal plant shutdown, when the reactor vessel head has been removed, the RHR system is designed to be capable of being aligned to assist the FPC and cleanup system in maintaining the fuel pool temperature within acceptable limits. In this mode the system is designed to cool water drawn from the fuel pool by passing it through an RHR system heat exchanger and then discharge the water back to the fuel pool;

f. Minimum flow bypass mode - The RHR system minimum flow bypass mode is designed to provide cooling for the RHR pumps during a small break LOCA that does not result in rapid reactor vessel depressurization to below the RHR system shutoff discharge pressure. This mode cools the pumps by providing a pump flow return line to the suppression pool that allows sufficient pump cooling flow to return to the pool until flow in the main discharge line is sufficient to provide adequate pump cooling. When flow in the main discharge lines is sufficient for cooling of the pumps, motor-operated valves in the minimum flow bypass line to the suppression pool automatically close so that all of the system's flow is directed into the main discharge lines;

g. Standby mode - During normal power operation the RHR system is required to be available for the LPCI mode in the event a LOCA occurs. The system is normally maintained in the standby mode. In this mode the system is aligned with the pumps' suction from the suppression pool and all other valves aligned so that only the injection valves are required to open and the RHR pumps started for LPCI flow to be delivered to the reactor following depressurization.

Until adequate flow is established, the RHR pumps are cooled automatically by flow through the minimum flow valves;

h. Reactor steam condensing mode - The reactor steam condensing mode has been deactivated and will no longer be utilized for CGS. No credit has been taken for the steam condensing mode in any safety analysis; and

i. The potential for exceeding the 100°F/hr cooldown limit during the cooldown mode is minimized by precautions and limitations in the appropriate operating procedures.

5.4.7.1.2 Design Basis for Isolation of Residual Heat Removal System from Reactor Coolant System

Interlocks are provided to inhibit shutdown cooling mode alignment whenever reactor pressure is above the design pressure of the low pressure portions of the RHR system (approximately 135 psig).

The low pressure portions of the RHR system are isolated from full reactor pressure whenever the primary system pressure is above the RHR system design pressure. The minimum pressure above which LPCI protection is required is below the design pressure of the low pressure portions of the RHR system. These interlocks also provide protection of the low pressure portions of the RHR system. These interlocks can be reset when pressure has been reduced to approximately 135 psig. The LPCI injection valves are interlocked to prevent opening when reactor pressure is above approximately 460 psig, which also provides protection for the low pressure portions of the RHR system. In addition, automatic isolation may occur for reasons of vessel water inventory retention which is unrelated to piping pressure ratings. See Section 5.2.5 for an explanation of the leak detection system and the isolation signals.

The RHR pumps are protected against damage from a closed discharge valve by means of automatic minimum flow valves, which open when the main line flow is low and close when the main line flow is greater than the setpoint specified in the Technical Specifications.

5.4.7.1.3 Design Basis for Pressure Relief Capacity

The relief valves in the RHR system are sized for one or both of the following bases:

a. Thermal relief,
b. Valve bypass leakage

Relief valves are set to ensure that the design pressure plus 10% accumulation is not exceeded anywhere in the system being protected. A check valve, RHR-V-209, is installed across RHR-V-9 to prevent thermal overpressurization between RHR-V-8 and RHR-V-9.

The relief valves protecting the RHR system are listed below (see Figure 5.4-15):

Relief Valve	Nominal Setpoint (psig)	Required Capacity (gpm)	Piping Location	Design Pressure (psig)
RHR-RV-88A	205	1	RHR pump suction from suppression pool	220 (loop A)
RHR-RV-88B	205	1		220 (loop B)
RHR-RV-88C	110	1		125 (loop C)
RHR-RV-5	183	1	RHR pump suction from recirculation pipe	220
RHR-RV-25A	487	1	RHR discharge	500
RHR-RV-25B	488	1	RHR discharge	500
RHR-RV-25C	493	1	RHR discharge	500
RHR-RV-30	103	1	RHR flush line to radwaste	125
RHR-RV-36*				

All RHR relief valves are purchased to ASME Section III, Class 2, requirements to match the requirements of the piping they are protecting. As such, the setpoint tolerance is plus or minus 3% for setpoints above 70 psi per ASME Section III, Paragraph NC-7600. Pressure buildups in isolated lines will be slow and discharges from relief valves on these lines will be small. Water hammer and other hydrodynamic loads are not considered a potential problem in RHR relief valve piping.

Redundant interlocks prevent opening valves to the low-pressure suction piping when the reactor pressure is above the shutdown range. These same interlocks initiate valve closure on increasing reactor pressure.

A pressure interlock prevents connecting the discharge piping to the primary system whenever the primary pressure is greater than the design value. In addition a high-pressure check valve will close to prevent reverse flow if the pressure should increase. Relief valves in the discharge piping are sized to account for leakage past the check valve.

The RHR cooling system is connected to higher pressure piping at (a) shutdown cooling suction, (b) shutdown cooling return, (c) LPCI injection, and (d) head spray. The vulnerability to overpressurization of each location is discussed in the following paragraphs:

* RHR-RV-36 has been permanently removed from Columbia Generating Station. It has been replaced with a blind-flanged "Testable Pipe Spool Assembly," RHR-TPSA-1.

The shutdown cooling suction piping has two gate valves (RHR-V-8 and RHR-V-9) in series which have independent pressure interlocks to prevent opening at high reactor pressure. No single active failure or operator error will result in overpressurization of the lower pressure piping. With the RHR pumps normally lined up to the suppression pool (RHR-V-6A and RHR-V-6B closed), the shutdown cooling suction line is protected from thermal expansion or from leakage past RHR-V-8 by RHR-RV-5. A bypass around RHR-V-6A may also be used to route leakage past RHR-V-8 and RHR-V-9 to the suppression pool. With all the RHR suction valves closed, the suction piping is protected from thermal expansion or leakage past the discharge check valves by RHR-RV-88A, RHR-RV-88B, and RHR-RV-88C. When the bypass around RHR-V-6A is not in service, it will be isolated using a single valve. This will allow the installed relief valves discussed above to protect the bypass piping.

The shutdown cooling return line has swing check valves (RHR-V-50A and RHR-V-50B) to protect it from higher vessel pressures. Additionally, a gate valve (RHR-V-53A and RHR-V-53B) is located in series and has a pressure interlock to prevent opening at high reactor pressures. No single active failure or operator error will result in overpressurization of the lower pressure piping.

Each LPCI injection line has a swing check valve (RHR-V-41A, RHR-V-41B, and RHR-V-41C) to protect it from higher vessel pressures. Additionally, a gate valve (RHR-V-42A, RHR-V-42B, and RHR-V-42C) is located in series and has pressure interlocks to prevent opening at high reactor vessel pressure. No single active failure or operator error will result in overpressurization of the lower pressure piping.

The head spray piping has three swing check valves in series [two belonging to the RCIC system and one (RHR-V-19) belonging to the RHR system], to protect it from higher vessel pressures. Two of the swing check valves have air operators but are only capable of opening the testable check valve if the differential pressure is less than 5.0 psid. Additionally, a globe valve (RHR-V-23) is located in series and has a pressure interlock to prevent opening at high reactor pressures. No single active failure or operator error will result in the overpressurization of the lower pressure piping.

Overpressurization protection of the RHR discharge piping for thermal expansion or from leakage past the head spray, shutdown injection, and LPCI isolation valves is provided by RHR-RV-25A, RHR-RV-25B, and RHR-RV-25C.

The RHR drain system to radwaste is protected from thermal expansion or from leakage past the isolation valves RHR-V-71A, RHR-V-71B, RHR-V-71C, RHR-V-72A, RHR-V-72B, and RHR-V-72C by RHR-RV-30.

5.4.7.1.4 Design Basis With Respect to General Design Criterion 5

The RHR system for this unit does not share equipment or structures with any other nuclear unit.

5.4.7.1.5 Design Basis for Reliability and Operability

The design basis for the shutdown cooling modes of the RHR system is that these modes are controlled by the operator from the control room. The operations performed outside of the control room using the normal shutdown is manual operation of a local flushing water admission valve, which is the means of ensuring that the suction line of the shutdown portions of the RHR system is filled and vented. In addition, the 0.75-in. bypass around RHR-V-6A would be isolated if necessary.

Two modes of operation provide the shutdown cooling function for the RHR system. One mode, the normal Shutdown Cooling Mode, is the preferred operational mode. Although preferred, this mode of RHR does not meet the redundancy and single failure requirements of IEEE 279 and 10 CFR 50 Appendix A, GDC 34. As a result, a second shutdown cooling mode, the Alternate Shutdown Cooling Mode, is provided and is the shutdown cooling mode credited to meet the requirements of IEEE 279 and GDC 34. This mode is safety related, Quality Class 1, Seismic Category 1, redundant and single failure proof. Since the normal Shutdown Cooling Mode of RHR is preferred for CGS, the components required for the operation of this mode are maintained as safety related, Quality Class 1.

For the normal shutdown cooling mode, two separate shutdown cooling loops are provided. The reactor coolant temperature can be brought to 212°F in less than 36 hr with only one loop in operation. With the exception of the shutdown suction including the reactor recirculation loop suction and discharge valves, and shutdown return, the entire RHR system is safety grade and redundant, is part of the ECCS and containment cooling systems, and is designed with the flooding protection, piping protection, power separation, etc., required of such systems. See Section 6.3 for an explanation of the design bases for ECCS systems. Shutdown cooling suction and discharge valves are required to be powered from both offsite and standby emergency power for purposes of isolation and shutdown following a loss of offsite power. In the event that the outboard shutdown cooling suction supply valve (RHR-V-8) fails to open from the control room, an operator may be sent to open the valve by hand.

If the attempt to open the outboard valve proves unsuccessful, or the inboard shutdown cooling suction supply valve (RHR-V-9) fails to open, the operator will establish the alternate shutdown cooling mode path as described in the notes to Figure 15.2-10, Activity C1 or C2.

For the alternate shutdown cooling mode, if vessel depressurization were to be achieved by manual actuation of relief valves, three valves would need to be actuated to pass sufficient steam flow to depressurize the vessel.

Low-pressure liquid flow test results are presented in NEDE-24988-P. This test program adequately demonstrated the ability to use SRVs in the alternate shutdown cooling mode.

Following reactor depressurization (i.e., 100°F/hr), an alternate shutdown coolant flow rate of 2600 gpm would be required to bring the reactor to a shutdown condition. This flow capacity can be achieved by using one ADS valve. However, three valves are always available.

Calculations demonstrate that in the alternate shutdown cooling mode, with one RHR pump in operation, the total system resistance head is 550 ft using one SRV valve. At this calculated head, the pump capacity is 4000 gpm and the reactor pressure is 160 psig.

The air supply for the ADS valves is discussed in Sections 5.2.2, 6.2.2, and 7.3.1.

5.4.7.1.6 Design Basis for Protection from Physical Damage

The RHR system is designed to the requirements of Table 3.2-1. With the exception of the common shutdown cooling line, redundant components of the RHR system are physically located in different quadrants of the reactor building, and are supplied from independent and redundant electrical divisions. Further discussion on protection from physical damage is provided in Section 6.3.

5.4.7.2 Systems Design

5.4.7.2.1 System Diagrams

All of the components of the RHR system are shown in Figure 5.4-15. A description of the controls and instrumentation is presented in Section 7.3.1.1.1.

A process diagram and process data are shown in Figures 5.4-16 and 5.4-17. All of the sizing modes of the system are shown in the process data. The functional control diagram for the RHR system is shown in Figure 7.3-10.

Interlocks are provided (a) to prevent draining vessel water to the suppression pool, (b) to prevent opening vessel suction valves above the suction line design pressure, or above the discharge line design pressure with the pump operating at shutoff head, (c) to prevent inadvertent opening of drywell spray valves, and (d) to prevent pump start when suction valve(s) are not open. This interlock is defeated for the RHR FPC assist mode (see Section 9.1.3).

The RHR system may be used to supplement the cooling capacity of the FPC system. This mode requires the installation of spool pieces and the opening of normally locked closed valves (see Section 9.1.3.2 for details).

The normal shutdown cooling mode of RHR loop B can be aligned to return a portion of the cooling flow back into the reactor vessel via the RCIC head spray nozzle.

The LPCS system may be cross tied with the RHR system to provide a flow path from the CST to the LPCS system via RHR. This preoperational alignment provided clean water to the LPCS system during flushing and provided a flowpath to the vessel for the core spray sparger test. This spoolpiece is not expected to be used again during the lifetime of the plant.

The administrative controls used for these spoolpieces, interlocks, and valves are procedurally regulated to ensure proper system function.

5.4.7.2.2 Equipment and Component Description

a. System main pumps

The RHR main system pumps are motor-driven deepwell pumps with mechanical seals. The pumps are sized on the basis of the LPCI mode (modes A1 and A2, see Figure 5.4-17). Design pressure for the pump suction structure is 220 psig with a temperature range from 40°F to 360°F. Design pressure for the pump discharge structure is 500 psig. The bases for the design temperature and pressure are maximum shutdown cut-in pressures and temperature, minimum ambient temperature, and maximum shutoff head. The pump housing is carbon steel and the shaft is stainless steel. System configuration (elevation, piping design, etc.) ensures that minimum pump NPSH requirements are met with margin.

Figures 5.4-18 through 5.4-20 are the actual pump performance curves.

The RHR pumps are designed for the life of the plant (40 years) and tested for operability assurance and performance as follows:

1. In-shop tests, including: (a) hydrostatic tests of pressure retaining parts at 1.5 times the design pressure, (b) performance tests to determine the total developed head at zero flow and design flow, and (c) NPSH requirements.

2. After the pumps were installed in the plant, they underwent (a) the system hydro test, (b) functional tests, (c) periodic testing to verify operability in accordance with the Inservice Testing (IST) Program Plan, and (d) about 1 month of operation each year for a refueling shutdown (shutdown operation time has been reduced coincident with reduced outage times).

3. In addition, the pumps are designed for a postulated single operation of 3 to 6 months for one accident during the 40 year life of the plant.

A listing of GE operating experience of Ingersoll-Rand RHR pumps is provided in Tables 5.4-3 and 5.4-4.

b. Heat exchangers

The RHR system heat exchangers are sized on the basis of the duty for the shutdown cooling mode (mode E of the Process Data). All other uses of these exchangers require less cooling surface.

Flow rates are 7450 gpm (rated) on the shell side and 7400 gpm (rated) on the tube side (service water side). Rated inlet temperature is 95°F tube side. Design temperature range of both shell and tube sides are 40°F to 480°F. The tube side water temperature may be as low as 32°F. The low temperature condition is acceptable, based on compliance with the ASME III, Class 2, code. Design pressure is 500 psig on both sides. Fouling allowances are 0.0005 shell side and 0.002 tube side. The construction materials are carbon steel for the pressure vessel with stainless steel tubes and stainless steel clad tube sheet.

c. Valves

All of the directional valves in the system are conventional gate, globe, and check valves designed for nuclear service. The injection valves, reactor coolant isolation valves, and pump minimum flow valves are high speed valves, as operation for LPCI injection or vessel isolation requires. Valve pressure ratings are specified as necessary to provide the control or isolation function: i.e., all vessel isolation valves are rated as Class 1 nuclear valves rated at the same pressure as the primary system.

The pump minimum flow valves (RHR-FCV-64) open automatically at main line flows less than approximately 800 gpm. This allows flow to return to the suppression pool through the minimum flow bypass line, which branches off the main line upstream of the flow element. The minimum flow valve closes at main line flows greater than approximately 900 gpm and forces the entire pump discharge flow through the main line. The minimum flow valve controls meet IEEE-279 requirements.

To prevent loss of vessel inventory to the suppression pool when operating shutdown cooling or RHR/FPC assist mode, the minimum flow valve is not

permitted to open. Administrative controls ensure that the valve is returned to normal status following the conclusion of shutdown cooling.

d. Restricting orifices

The metering orifices in the discharge lines do not serve as restricting orifices. The piping for each mode of RHR operation has been investigated to ensure that the resistance is low enough to allow the rated flows given in Figure 5.4-17 yet high enough to prevent pump runout. Restricting orifices are necessary in the system test lines to prevent excessive runout during SPC and test modes and in the main discharge line to prevent excessive runout for LPCI A & C systems. In addition, restriction orifices are installed ahead of the RHR-V-53A and RHR-V-53B valves to prevent excessive pump runout or valve cavitation during the shutdown cooling mode. Figure 5.4-15 indicates the location of restricting orifices.

Additionally, two orifices are installed in the FPC system to minimize cavitation and limit flow when RHR is used to assist FPC.

e. ECCS portions of the RHR system

The ECCS portions of the RHR system include those sections described in Figure 5.4-16.

The route includes suppression pool suction strainers, suction piping, RHR pumps, discharge piping, injection valves, and drywell piping into the vessel nozzles and core region of the reactor vessel.

The SPC components include pool suction strainers, suction piping, pumps, heat exchangers, and pool return lines.

Containment spray components are the same as SPC except that the spray headers replace the pool return lines.

5.4.7.2.3 Controls and Instrumentation

Controls and instrumentation for the RHR system are described in Section 7.3. The RHR system relief valve capacities and settings are listed in Section 5.4.7.1.3.

5.4.7.2.4 Applicable Codes and Classifications

See Section 3.2.

5.4.7.2.5 Reliability Considerations

The RHR system has included the redundancy requirements of Section 5.4.7.1.5. Two redundant loops have been provided to remove residual heat. With the exception of the common shutdown cooling line and the shutdown return valves (RHR-V-53A and RHR-V-53B) which are powered from the same division power source, all mechanical and electrical components are separate. Either loop is capable of cooling down the reactor within a reasonable length of time.

5.4.7.2.6 Manual Action

RHR (shutdown cooling mode)

In the shutdown cooling mode of operation, when reactor vessel pressure is 48 psig or less, a service water pump is started and cooling water flow established through a heat exchanger. The RHR pump suction valve RHR-V-4A and/or RHR-V-4B is then closed and shutdown cooling isolation valves RHR-V-9 and RHR-V-8 opened. RHR pump suction valve RHR-V-6A and/or RHR-V-6B is then opened. Pump suction piping is prewarmed and provided a nominal flush by opening valves to radwaste. These effluent valves to radwaste are then closed and the RHR pump is started. The cooldown rate is controlled by adjusting the heat exchanger outlet valve and heat exchanger bypass valve to achieve the desired temperature of the water returning to the reactor vessel while maintaining the total flow at approximately 7450 gpm.

If prewarming valves were accidentally left open following initiation of shutdown cooling, reactor pressure vessel (RPV) coolant inventory would drain to radwaste. If loss of inventory remained undetected and makeup did not occur, isolation valves RHR-V-8 and RHR-V-9 would automatically close at the RPV scram level specified in the Technical Specifications; depressurization or loss of water from the RHR system causes a low pressure alarm in the RHR discharge piping.

If the bypass around RHR-V-6A were inadvertently left open following the initiation of shutdown cooling using RHR loop B, the RPV coolant inventory would drain to the suppression pool at a flow rate of 1 gpm or less. If this loss of inventory remained undetected and makeup did not occur, RHR-V-8 and RHR-V-9 would automatically close at the RPV scram level.

The manual actions required for the most limiting failure are discussed in Section 5.4.7.1.5.

5.4.7.3 Performance Evaluation

Thermal performance of the RHR heat exchangers is based on the capability to remove enough sensible and decay heat from the reactor system to reduce the bulk reactor coolant temperature

to 125°F within 25 hours after control rod insertion, with two RHR loops in operation. Because cooldown is usually a controlled operation, maximum service water temperature less 10°F is used as the service water inlet temperature. These are nominal design conditions; if the service water temperature is higher, the exchanger capabilities are reduced and the cooldown time may be longer or vice versa.

5.4.7.3.1 Shutdown Cooling With All Components Available

No typical curve is included here to show vessel cooldown temperatures versus time due to the infinite variety of such curves due to (a) clean steam systems that use the main condenser as the heat sink when nuclear steam pressure is insufficient to maintain steam air ejector performance, (b) the fouling of the heat exchangers, (c) operator use of one or two cooling loops, (d) coolant water temperature, and (e) system flushing time. Since the exchangers are designed for the fouled condition with relatively high service water temperature, the units have excess capability to cool when first used at high vessel temperatures. Total flow mix temperature is controlled to avoid exceeding 100°F/hr cooldown rate. See Figure 5.4-21 for minimum shutdown cooling time to reach 212°F.

5.4.7.3.2 Shutdown Cooling With Most Limiting Failure

Shutdown cooling under conditions of the most limiting failure is discussed in Section 5.4.7.1.5. The capability of the heat exchanger for any time period is balanced against residual heat, pump heat, and sensible heat. The excess over residual heat and pump heat is used to reduce the sensible heat.

5.4.7.4 Preoperational Testing

The preoperational test program and startup test program were used to generate data to verify the operational capabilities of equipment in the system, such as each instrument, setpoint, logic element, pump, heat exchanger, valve, and limit switch. In addition these programs verified the capabilities of the system to provide the flows, pressures, cooldown rates, and reaction times required to perform all system functions as specified for the system or component in the System Data Sheets and Process Data. Logic elements were tested electrically; valves, pumps, controllers, relief valves were tested mechanically; finally the system was tested for total system performance against the design requirements as specified above using both the offsite power and standby emergency power. Preliminary heat exchanger performance was evaluated by operating in the pool cooling mode, but a vessel cooldown was used for the final check due to the small temperature differences available with pool cooling (see Section 14.2).

5.4.8 REACTOR WATER CLEANUP SYSTEM

The reactor water cleanup (RWCU) system is an auxiliary system, a small part of which is part of the RCPB up to and including the outermost containment isolation valve. The other portions of the system are not part of the RCPB and are isolated from the reactor.

5.4.8.1 Design Bases

5.4.8.1.1 Safety Design Bases

The RCPB portion of the RWCU system meets the requirements of Regulatory Guides 1.26 and 1.29 to

a. Prevent excessive loss of reactor coolant,

b. Prevent the release of radioactive material from the reactor,

c. Isolate the cleanup system from the RCPB, and

d. Prevents loss of liquid reactivity control material from the reactor vessel during standby liquid control (SLC) system operation.

5.4.8.1.2 Power Generation Design Bases

The RWCU system

a. Removes solid and dissolved impurities from reactor coolant such that the water purity meets Regulatory Guide 1.56,

b. Discharges excess reactor water during startup, shutdown, and hot standby conditions,

c. Minimizes temperature gradients in the recirculation piping and vessel during periods when the main recirculation pumps are unavailable,

d. Minimizes cleanup system heat loss, and

e. Enables the major portion of the RWCU system to be serviced during reactor operation.

5.4.8.2 System Description

The RWCU system (see Figures 5.4-22 and 5.4-23) continuously purifies reactor water during all modes of reactor operation. The system takes suction from the inlet of each reactor main recirculation pump and from the reactor pressure vessel bottom head. Processed water is returned to the reactor pressure vessel, to the main condenser, or radwaste.

The cleanup system can be operated at any time during planned operations, or it may be shut down. The cleanup system is classified as a primary power generation system. The cleanup system is not an engineered safety system.

Major equipment of the RWCU system is located in the reactor building. This equipment includes the pumps and the regenerative and nonregenerative heat exchangers. Filter-demineralizers and supporting equipment are located in the radwaste building. The entire system is connected by associated valves and piping; controls and instrumentation provide proper system operation. Design data for the major pieces of equipment are presented in Table 5.4-5.

Reactor water is cooled in the regenerative and nonregenerative heat exchangers, filtered, demineralized, and returned to the reactor pressure vessel through the shell side of the regenerative heat exchanger.

The system pump is capable of producing a nominal flow of 181,300 lbm/hr. Two filter demineralizer units are used to process this quantity of water. The system can operate at reduced flow rates with one filter demineralizer unit.

The temperature of water processed through the filter-demineralizers is limited by the resin operating temperature. Therefore, the reactor water must be cooled before being processed in the filter-demineralizers. The regenerative heat exchanger transfers heat from the tube side (hot process) to the shell side (cold process). The shell side flow returns to the reactor. The nonregenerative heat exchanger cools the process further by transferring heat to the reactor building closed cooling water system.

The filter-demineralizers (see Figure 5.4-24) are pressure precoat type filters using ion exchange resins. Spent resins are not regenerable and are sluiced from the filter-demineralizers to a backwash receiving tank from which they are transferred to the radwaste system for processing and disposal. To prevent resins from entering the RRC in the event of complete failure of a filter-demineralizer resin septum, a strainer is installed on each filter-demineralizer. Each strainer and filter-demineralizer vessel has a control room alarm that is energized by high differential pressure. Further increase in differential pressure will isolate the filter-demineralizer. The backwash and precoat cycle for a filter-demineralizer is automatic to prevent operational errors such as inadvertent openings of valves that would initiate a backwash or contaminate reactor water with resins. The filter-demineralizer piping

configuration is arranged to ensure that transfers are complete and crud traps are avoided. A bypass line is provided around the filter-demineralizers.

On low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided in the common influent header and in each effluent line of the filter-demineralizers for continuous indication and recording of system conductivity. High conductivity is annunciated in the control room. The influent sample point is also used as the normal source of reactor coolant grab samples. Sample analysis also indicates the effectiveness of the filter-demineralizers.

The suction line of the RCPB portion of the RWCU system contains two motor-operated isolation valves that automatically close in response to signals from the RPV low water level and the leak detection system. The outboard isolation valve, RWCU-V-4, automatically closes in response to signals from actuation of the SLC system and high nonregenerative heat exchanger outlet water temperature. These actions prevent (a) loss of reactor coolant, (b) release of radioactive material from the reactor, (c) removal of liquid reactivity control material, and (d) thermal damage to ion-exchange resins. The RCPB isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing.

A remote manual-operated gate valve on the return line to the reactor provides long-term leakage control. Instantaneous reverse flow isolation is provided by check valves in the RWCU piping.

Operation of the RWCU system is controlled from the main control room. Resin-changing operations, which include backwashing and precoating, are controlled from the radwaste control room in the radwaste building.

A functional control diagram is provided in Figure 7.3-1.

5.4.8.3 System Evaluation

The RWCU system in conjunction with the condensate treatment system and FPC and cleanup system maintains reactor water quality during all reactor operating modes (normal, standby, startup, shutdown, and refueling). The RWCU components provide a system with the capability to support reactor operations at power levels up to 3629 MWt.

The component pressure and temperature design conditions are shown in Table 5.4-5. The process containing components (piping, valves, vessels, heat exchangers, pumps) are designed to the requirements of Section 3.2. The control requirements for the RCPB isolation valves are designed to the requirements of Table 7.3-5. The nonregenerative heat exchanger is sized to maintain the process temperature required for the cleanup demineralizer resin when the cooling capacity of the regenerative heat exchanger is reduced at times when flow is partially bypassed to the main condenser or radwaste.

5.4.8.4 Demineralizer Resins

Regulatory Guide 1.56 compliance is described in Section 1.8.

5.4.8.5 Reactor Water Cleanup Water Chemistry

5.4.8.5.1 Analytical Methods

Chemical analyses methods used for determination of conductivity, pH, and chloride content of primary coolant are as follows:

Conductivity	measured in accordance to ASTM-D-1125
pH	measured in accordance to ASTM-D-1293
Chloride	determined by ion chromatography in accordance with the vendor's operating manual

5.4.8.5.2 Relationship of Filter-Demineralizer Condition to Water Chemistry

The filter-demineralizer condition during normal power operation is related to inlet conductivity and water volume processed through the unit. The inlet conductivity is related to impurity concentration through the equivalent conductance of the constituents of the process fluid. System flow rates are measured and recorded to determine quantity of water processed.

Periodically, an On-Line NobleChem™ application will be performed, which injects platinum into the reactor coolant, resulting in a microscopic layer of the noble metal to be deposited onto the reactor internals.

Conductivity instrumentation is calibrated against laboratory flow cells in accordance with ASTM-D-1125. The alarm setpoints for the conductivity instrumentation at the inlet and outlet of the filter-demineralizers are set to indicate marginal performance or breakthrough of the filter-demineralizers.

The quantity of the principle ion(s) likely to cause demineralizer breakthrough are not calculated using conductivity as discussed in position 4.C of Regulatory Guide 1.56. Instead, actual ion sample data is taken and used to determine ion levels at the outlet of the filter-demineralizer. When sample data indicates resin breakthrough or the allowable pressure drop is exceeded, the filter-demineralizer is regenerated.

5.4.9 MAIN STEAM LINES AND FEEDWATER PIPING

5.4.9.1 Safety Design Bases

To satisfy the safety bases, the main steam and feedwater lines have been designed

a. To accommodate operational stresses, such as internal pressures and SSE loads, without a failure that could lead to the release of radioactivity in excess of the guideline values in published regulations, and

b. With suitable accesses to permit IST and inspections.

5.4.9.2 Power Generation Design Bases

To satisfy the design bases

a. The main steam lines have been designed to conduct steam from the reactor vessel over the full range of reactor power operation, and

b. The feedwater lines have been designed to conduct water to the reactor vessel over the full range of reactor power operation.

5.4.9.3 Description

The main steam piping is described in Section 10.3. The main steam and feedwater piping is shown in Figure 10.3-2.

The feedwater piping consists of two 24-in. O.D. lines which penetrate the containment and drywell and branch into three 12-in. lines each, which connect to the reactor vessel. Each 24-in. line includes three containment isolation valves consisting of one check valve inside the drywell and one motor-operated gate valve and one check valve outside the containment. The design pressure and temperature of the feedwater piping between the reactor and maintenance valve is 1300 psig and 575°F. The Seismic Category I design requirements are placed on the feedwater piping from the reactor through the outboard isolation valve and connected piping up to and including the first isolation valve in the connected piping.

The materials used in the piping are in accordance with the applicable design code and supplementary requirements described in Section 3.2.

The feedwater system is further described in Sections 7.7.1, 7.7.2, and 10.4.7.

5.4.9.4 Safety Evaluation

Differential pressure on reactor internals under the assumed accident condition of a ruptured steam line is limited by the use of flow restrictors and by the use of four main steam lines. All main steam and feedwater piping is designed in accordance with the requirements defined in Section 3.2.

5.4.9.5 Inspection and Testing

Inspection and testing of the main steam lines and feedwater piping is performed in accordance with the ISI Program Plan to ensure compliance with applicable codes.

5.4.10 PRESSURIZER

Not Applicable to BWRs.

5.4.11 PRESSURIZER RELIEF DISCHARGE SYSTEM

Not Applicable to BWRs.

5.4.12 VALVES

5.4.12.1 Safety Design Bases

Line valves such as gate, globe, and check valves are located in the fluid systems to perform a mechanical function. Valves are components of the system pressure boundary and, having moving parts, are designed to operate efficiently to maintain the integrity of this boundary.

The valves operate under the internal pressure/temperature loading as well as the external loading experienced during the various system transient operating conditions. The design criteria, the design loading, and acceptability criteria are as required in Section 3.9.3 for ASME Class 1, 2, and 3 valves. Compliances with ASME Codes are discussed in Section 5.2.1.

5.4.12.2 Description

Line valves furnished are manufactured standard types, designed and constructed in accordance with the requirements of ASME Section III for Class 1, 2, and 3 valves. All materials, exclusive of seals, packing and wearing components, are designed to endure the 40-year plant life under the environmental conditions applicable to the particular system when appropriate maintenance is periodically performed.

Power operators have been sized to operate successfully under the maximum differential pressure determined in the design specification or design basis calculations.

5.4.12.3 Safety Evaluation

Line valves are shop tested by the manufacturer for performability. Pressure retaining parts are subject to the testing and examination requirements of Section III of the ASME Code. To minimize internal and external leakage past seating surfaces, maximum allowable leakage rates are stated in the design specifications for both back seat as well as the main seat for gate and globe valves.

Valve construction materials are compatible with the maximum anticipated radiation dosage for the service life of the valves.

5.4.12.4 Inspection and Testing

Valves serving as containment isolation valves and which must remain closed or open during normal plant operation may be partially exercised during this period to assure their operability at the time of an emergency or faulted conditions. Other valves, serving as a system block or throttling valves, may be exercised when appropriate.

Motors used with valve actuators are furnished in accordance with applicable industry standards. Each motor actuator has been assembled, factory tested or tested in-situ, and adjusted on the valve for proper operation, position and torque switch setting, position transmitter function (where applicable), and speed requirements. A selected set of motor-operated valves with active safety functions (Generic Letter 89-10 Program and Generic Letter 96-05 Program) have additionally been tested to demonstrate adequate stem thrust (or torque) capability to open (or close) the valve within the specified time at specified maximum expected differential pressure. Modifications have been made to several gate valves to eliminate the possibility for internal pressure locking forces which could prevent the actuator from unseating the valve (Generic Letter 95-07 Program).

Tests verified no mechanical damage to valve components during full stroking of the valve. Suppliers were required to furnish assurance of acceptability of the equipment for the intended service based on any combination of

a. Test stand data,
b. Prior field performance,
c. Prototype testing, and
d. Engineering analysis.

Preoperational and operational testing performed on the installed valves consists of total circuit check out and performance tests to verify design basis capability including speed requirements at specified differential pressure.

5.4.13 SAFETY AND RELIEF VALVES

A listing of the safety and relief valves is provided in Table 5.4-6.

5.4.13.1 Safety Design Bases

Overpressure protection is provided at isolatable portions of systems in accordance with the rules set forth in the ASME Code, Section III for Class 1, 2, and 3 components.

5.4.13.2 Description

Pressure relief valves are designed and constructed in accordance with the same code class as that of the line valves in the system.

The design criteria, design loading, and design procedure are described in Section 3.9.3.

5.4.13.3 Safety Evaluation

The use of pressure relieving devices will ensure that overpressure will not exceed 10% above the design pressure of the system. The number of relieving devices on a system or portion of a system have been determined on an individual component basis.

5.4.13.4 Inspection and Testing

The valves are inspected and tested in accordance with ASME Section XI, if required.

Other than the main steam relief valves, no provisions are to be made for inline testing of pressure relief valves, other than set pressure and leakage. Certified set pressures and relieving capacities are stamped on the body of the valves by the manufacturer and further examinations would necessitate removal of the component. For subsequent set pressure changes, the valve body will be stamped or a stamped tag will be attached indicating the new pressure.

5.4.14 COMPONENT AND PIPING SUPPORTS

Support elements are provided for those components included in the RCPB and the connected systems.

5.4.14.1 Safety Design Bases

Design loading combinations, design procedures, and acceptability criteria are as described in Section 3.9.3. Flexibility calculations and seismic analysis for Class 1, 2, and 3 component and piping supports within the ASME boundary of jurisdiction conform with the appropriate requirements of ASME Section III, Subsection NF. Outside the ASME boundary steel structures conform to the AISC manual of Steel Construction.

Spacing and size of pipe support elements were based on the piping analysis performed in accordance with ASME Section III and further described in Section 3.7. Standard manufacturer hanger types were used and fabricated of materials per ASME Section III, Subsection NF.

5.4.14.2 Description

The use and location or rigid-type supports, variable or constant spring-type supports, and anchors or guides are determined from the results of static and dynamic analyses of the associated piping systems. The normal and transient (including seismic) support point loads generated by the piping analyses are combined as prescribed by Sections 3.9.3 and 3.7, and then utilized as the design basis loadings for each affected pipe support.

Typically, components support elements are manufacturers' standard items which are purchased with certified load capacity data reports. Nonstandard support structures and pressure boundary attachments are qualified by detailed structural analyses in compliance with applicable load combinations and governing design codes.

As described by Sections 5.4.14.1 and 5.4.14.2, each component support system has been rigorously evaluated with all due consideration for extreme loading conditions and satisfaction of conservative design allowable stresses. This demonstration of structural adequacy combined with a comprehensive testing and inspection program (see Section 5.4.14.3) constitutes the safety evaluation basis for these passive support elements.

5.4.14.3 Inspection and Testing

After completion of the installation and balancing of a support system, all hanger elements were visually examined to ensure that they were in correct adjustment to their cold setting position. On initial hot startup operations, thermal growth was observed and it was confirmed that all spring-type hangers and snubbers were functioning properly between their hot and cold setting positions. In addition, during power ascension testing critical systems were instrumented and monitored for vibration response under normal and plant transient conditions. The results of these tests showed all systems to be functioning as predicted by design analyses and thus all systems were accepted as operable and in compliance with the governing ASME Code.

5.4.15 HIGH-PRESSURE CORE SPRAY SYSTEM

See Section 6.3 for a description of the HPCS system.

5.4.16 LOW-PRESSURE CORE SPRAY SYSTEM

See Section 6.3 for a description of the LPCS system.

5.4.17 STANDBY LIQUID CONTROL SYSTEM

See Section 9.3.5 for a description of the SLC system.

5.4.18 REFERENCES

5.4-1 Ianni, P. W., "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors," APED-5458, March 1968.

5.4-2 "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, General Electric Co., Atomic Power Equipment Department, March 1969.

5.4-3 "Power Uprate with Extended Load Line Limit Safety Analysis for WNP-2," NEDC-32141P, General Electric Company.

5.4-4 "Generic Evaluations of General Electric Boiling Water Reactor Power Uprate - Volume I," NEDC-31984P, General Electric Company.

5.4-5 "Reactor Core Isolation Cooling System (RCIC)," Design Basis Document, Section 315.

Table 5.4-1

Reactor Coolant Pressure Boundary Pump and Valve Description[a]

Location	Active/Inactive	Valve	Reference Figure
Valve Description			
RHR vessel in	Active	RHR-V-41A	5.4-15
	Active	RHR-V-41B	5.4-15
	Active	RHR-V-41C	5.4-15
		(E12F041A, B, C)	
	Active	RHR-V-42A	5.4-15
	Active	RHR-V-42B	5.4-15
	Active	RHR-V-42C	5.4-15
		(E12F042A, B, C)	
	Inactive	RHR-V-111A	5.4-15
	Inactive	RHR-V-111B	5.4-15
	Inactive	RHR-V-111C	5.4-15
		(E12F111A, B, C)	
RHR/recirculation line in	Active	RHR-V-50A	5.4-15
	Active	RHR-V-50B	5.4-15
		(E12F050A, B)	
	Active	RHR-V-53A	5.4-15
	Active	RHR-V-53B	5.4-15
		(E12F053A, B)	
	Inactive	RHR-V-112A	5.4-15
	Inactive	RHR-V-112B	5.4-15
		(E12F112A,B)	
	Inactive	RHR-V-123A	5.4-15
	Inactive	RHR-V-123B	5.4-15
		(E12F099A, B)	
Head spray	Active	RHR-V-19 (E12F019)	5.4-15
	Active	RHR-V-23 (E12F023)	5.4-15
RHR shutdown cooling suction	Active	RHR-V-8 (E12F008)	5.4-15
	Active	RHR-V-9 (E12F009)	5.4-15
	Inactive	RHR-V-113 (E12F113)	5.4-15
RCIC vessel out	Active	RCIC-V-8 (E51F008)	5.4-11
	Active	RCIC-V-63 (E51F063)	5.4-11
	Active	RCIC-V-64 (E51F064)	5.4-11
	Active	RCIC-V-76 (E51F0076)	5.4-11

Table 5.4-1

Reactor Coolant Pressure Boundary Pump and Valve Description[a] (Continued)

Location	Active/Inactive	Valve	Reference Figure
(Nuclear boiler)			
Reactor vessel head	Inactive	MS-V-1 (B22F001)	10.3-2
	Inactive	MS-V-2 (B22F002)	10.3-2
Feedwater in	Active	RFW-V-10A	10.3-2
	Active	RFW-V-10B	10.3-2
		(B22F010A, B)	
	Inactive	RFW-V-11A	10.3-2
	Inactive	RFW-V-11B	10.3-2
		(B22F011A, B)	
	Active	RFW-V-32A	10.3-2
	Active	RFW-V-32B	10.3-2
		(B22F032A, B)	
	Active	RFW-V-65A	10.3-2
	Active	RFW-V-65B	10.3-2
		(B22F065A, B)	
Safety relief	Active	MS-RV-2A	10.3-2
	Active	MS-RV-3A	10.3-2
	Active	MS-RV-2D	10.3-2
	Active	MS-RV-2C	10.3-2
	Active	MS-RV-1B	10.3-2
	Active	MS-RV-2B	10.3-2
	Active	MS-RV-3C	10.3-2
	Active	MS-RV-3B	10.3-2
		(B22F013A-H)	
	Active	MS-RV-1A	10.3-2
	Active	MS-RV-1D	10.3-2
	Active	MS-RV-1C	10.3-2
	Active	MS-RV-4C	10.3-2
	Active	MS-RV-5C	10.3-2
		(B22F013J-N)	
	Active	MS-RV-4D	10.3-2
		(B22F013P)	
	Active	MS-RV-4B	10.3-2
	Active	MS-RV-4A	10.3-2

Table 5.4-1

Reactor Coolant Pressure Boundary Pump and Valve Description[a] (Continued)

Location	Active/Inactive	Valve	Reference Figure
		(B22F013R-S)	
	Active	MS-RV-5B	10.3-2
	Active	MS-RV-3D	10.3-2
		(B22F013U-V)	
Reactor water cleanup system	Inactive	RWCU-V-103	5.4-22
		(G33F103)	
Line suction	Active	RWCU-V-1 (G33F001)	5.4-22
	Active	RWCU-V-4 (G33F004)	5.4-22
	Inactive	RWCU-V-100 (G33F100)	5.4-22
	Inactive	RWCU-V-101	5.4-22
	Inactive	(G33F101)	
	Inactive	RWCU-V-102	5.4-22
		(G33F102)	
		RWCU-V-106	5.4-22
		(G33F106)	
Line discharge	Active	RWCU-V-40	5.4-22
		(G33F040)	
Drain to condenser	Active	MS-V-16	10.3-2
	Active	(B22F016)	
		MS-V-19	10.3-2
		(B22F019)	
MSIV	Active	MS-V-22A	10.3-2
	Active	MS-V-22B	10.3-2
	Active	MS-V-22C	10.3-2
	Active	MS-V-22D	10.3-2
	Active	(B22F022)	
	Active	MS-V-28A	10.3-2
	Active	MS-V-28B	10.3-2
	Active	MS-V-28C	10.3-2
		MS-V-28D	10.3-2
		(B22F028)	

Table 5.4-1

Reactor Coolant Pressure Boundary Pump and Valve Description[a] (Continued)

Location	Active/Inactive	Valve	Reference Figure
Drain to condenser (Recirculation)	Active	MS-V-67A	10.3-2
	Active	MS-V-67B	10.3-2
	Active	MS-V-67C	10.3-2
	Active	MS-V-67D (B22F067)	10.3-2
Recirculation pump suction	Inactive	RRC-V-23A	5.4-7
	Inactive	RRC-V-23B (B35F023)	5.4-7
Flow control (pump discharge)	Inactive[b]	RRC-V-60A	5.4-7
	Inactive[b]	RRC-V-60B (B35F060)	5.4-7
	Inactive	RRC-V-67A	5.4-7
	Inactive	RRC-V-67B (B35F067)	5.4-7
RCIC vessel head in	Active	RCIC-V-13 (E51F013)	5.4-11
	Active	RCIC-V-65 (E51F065)	5.4-11
	Active	RCIC-V-66 (E51F066)	5.4-11
HPCS in	Active	HPCS-V-4 (E22F005)	6.3-4
	Active	HPCS-V-5 (E22F004)	6.3-4
	Inactive	HPCS-V-38 (E22F038)	6.3-4
LPCS in	Active	LPCS-V-5 (E21F005)	6.3-4
	Active	LPCS-V-6 (E21F006)	6.3-4
	Inactive	LPCS-V-51 (E21F051)	6.3-4
Standby liquid control in	Active	SLC-V-4A	9.3-14
	Active	SLC-V-4B	9.3-14
	Active	SLC-V-6	9.3-14
	Active	SLC-V-7	9.3-14
	Inactive	SLC-V-8	9.3-14
Pump description			
Recirculation pump	Inactive	RRC-P-1A	5.4-7
	Inactive	RRC-P-1B (B35C001)	5.4-7

Table 5.4-1

Reactor Coolant Pressure Boundary Pump and Valve Description[a] (Continued)

[a] In addition to the process valves listed herein, there are instrument test conditions, drain valves, and sampling valves less than 1 in. nominal size within the RCPB. See associated system flow diagram figures.

[b] Mechanically blocked in the full open position.

NOTE:

Active components are those whose operability is relied on to perform a safety function during the transients or accidents.

Inactive components are those whose operability (e.g., valve opening or closure, pump operation or trip) is not relied on to perform the system's safety function during the transients or accidents.

Table 5.4-2

Reactor Recirculation System Design Characteristics

Description	
External loops	2
Pump sizes (nominal O.D.)	
Pump suction, in.	24
Pump discharge, in.	24
Discharge manifold, in.	16
Recirculation inlet lines, in.	12
Design pressure (psig)/design temperature (°F)	
Suction piping and valve up to and including pump suction nozzle	1250/575
Pump, discharge valves, and piping between	1650/575
Piping after discharge blocking valve up to vessel	1550/575
Vessel bottom drain	1275/575
Operation at pump related conditions	
Recirculation pump	
Flow, gpm	47,200
Flow, lb/hr	17.85×10^6
Total developed head, ft	$\boxed{805}$
Suction pressure (static), psia	1025
Required NPSH, ft	115
Water temperature (maximum), °F	533
Pump brake hp (minimum)	8340
Flow velocity at pump suction (approximate), ft/sec	41.5
Pump motor	
Voltage rating	6600
Speed, rpm	1780
Motor rating, hp	8900
Phase	3
Frequency	60
Motor rotor inertia ($lb\text{-}ft^2$)	21,500 (RRC-M-P/1B) 20,600 (RRC-M-P/1A)
Jet pumps	
Number	20
Total jet pump flow, lb/hr	108.5×10^6
Total I.D., in.	6.4

Table 5.4-2

Reactor Recirculation System Design Characteristics (Continued)

Description	
Diffuser I.D., in.	19.0
Nozzle I.D. (five each), in.	1.3
Diffuser exit velocity, ft/sec	16.2
Jet pump head, ft	88.19
Flow control valve[a]	
Type	Ball
Material	Austenitic stainless steel
Valve wide open C_V (minimum), gpm/psi	7000
Valve size diameter, in.	24
Recirculation block valve	
Type	Gate valve
Actuator	Motor
Material	Austenitic stainless steel
Valve size diameter, in.	24
Recirculation pump flow measurement	
Type	Elbow taps
Rated flow (gpm)	47,200
Flow element location	Pump suction line
Range	20-115% rated pump flow
Accuracy (% rated pressure drop)	± 9%
Repeatability (% rated pressure drop)	± 4%

[a] Mechanically blocked in the full open position.

Table 5.4-3

Operating Experience of Ingersoll-Rand Emergency Core Cooling Systems Pumps[a,b]

Plant	*Pump*	*Time (hr)*
Hatch 2	*RHR 2A*	*864*
	2B	*1112*
	2C	*629*
	2D	*569*
	LPCS 2A	*13.5*
	2B	*11.8*
Chinshan 1	*RHR*	*100*
	Core spray	*30*
Chinshan 2	*RHR*	*75*
	Core spray	*20*

[a] *The italicized information is historical and was provided to support the application for an operating license.*

[b] *No problems have been reported on these pumps. Pump design principles applied by Ingersoll-Rand to these units are not unique. Assurance of a predictable functional reliability is also provided by a history of design, production, and application of pumps for similar pumping requirements in other nuclear and nonnuclear applications.*

Table 5.4-4

Operating Experience of Similar Ingersoll-Rand Pumps for BWR Projects Under Review[a,b]

Year	*Size Range (gpm)*	*Number of Pumps*
1963	*< 4000*	*12*
1964	*< 3000*	*24*
1965	*< 5000*	*32*
1966	*< 4500*	*39*
1967	*< 5000*	*39*
	8000	*3*
1968	*< 6500*	*25*
	9000	*6*
	11000	*9*
1969	*< 6500*	*39*
	8000-9000	*9*
1970	*< 6500*	*33*
	8000	*14*
	12,000	*6*
1971	*< 6500*	*53*
	9000	*3*
	10,000-12,000	*12*
1972	*< 6500*	*44*
	8000	*18*
	10,000-12,000	*18*
1973	*< 6500*	*41*
	8000	*8*
	10,000-13,800	*20*
1974	*< 6500*	*32*
	8000	*2*
	10,000-13,800	*30*
1975	*< 7500*	*76*
	8500	*18*
	10,000-13,800	*50*
1976	*8500*	*9*

[a] *The italicized information is historical and was provided to support the application for an operating license.*

[b] *The vertical pumps used for ECCS functions at CGS are sized at 1200 to 8100 gpm. They are multistaged axial pumps. Included here is a partial list of the application history for similar pumps made by the same vendor.*

Although the operating experience in nuclear applications is just beginning, the postoperating experience in nonnuclear applications with these vertical pumps is very extensive. It indicates that the CGS ECCS pumps can be expected to operate as required. In reviewing this table, the generic pump design should be recalled because larger capacity pumps are configured from stages that comprise the smaller capacity pumps. Design refinements are evident in the capacity growth of these stages, whether in single, double, or multiple axial stackups.

Table 5.4-5

Reactor Water Cleanup System

Equipment		Design Data
Main Cleanup Recirculation Pumps		
Number		2
Capacity (each)		100% (@90 bhp)
Design temperature, °F		575
Design pressure, psig		1420
Discharge head at shutoff, ft		575
Minimum available NPSH, ft		16
Heat Exchangers		
	Regenerative	Nonregenerative
Number	1 (3 shells)	1 (2 shells)
Shell design pressure, psig	1420	150
Shell design temperature, °F	575	370
Tube design pressure, psig	1420	1420
Tube design temperature, °F	575	575
Filter-Demineralizers		
Type		Pressure precoat
Number		2
Design temperature, °F		150
Design pressure, psig		1450

Table 5.4-6

Safety and Relief Valves for Piping Systems
Connected to the Reactor Coolant Pressure Boundary

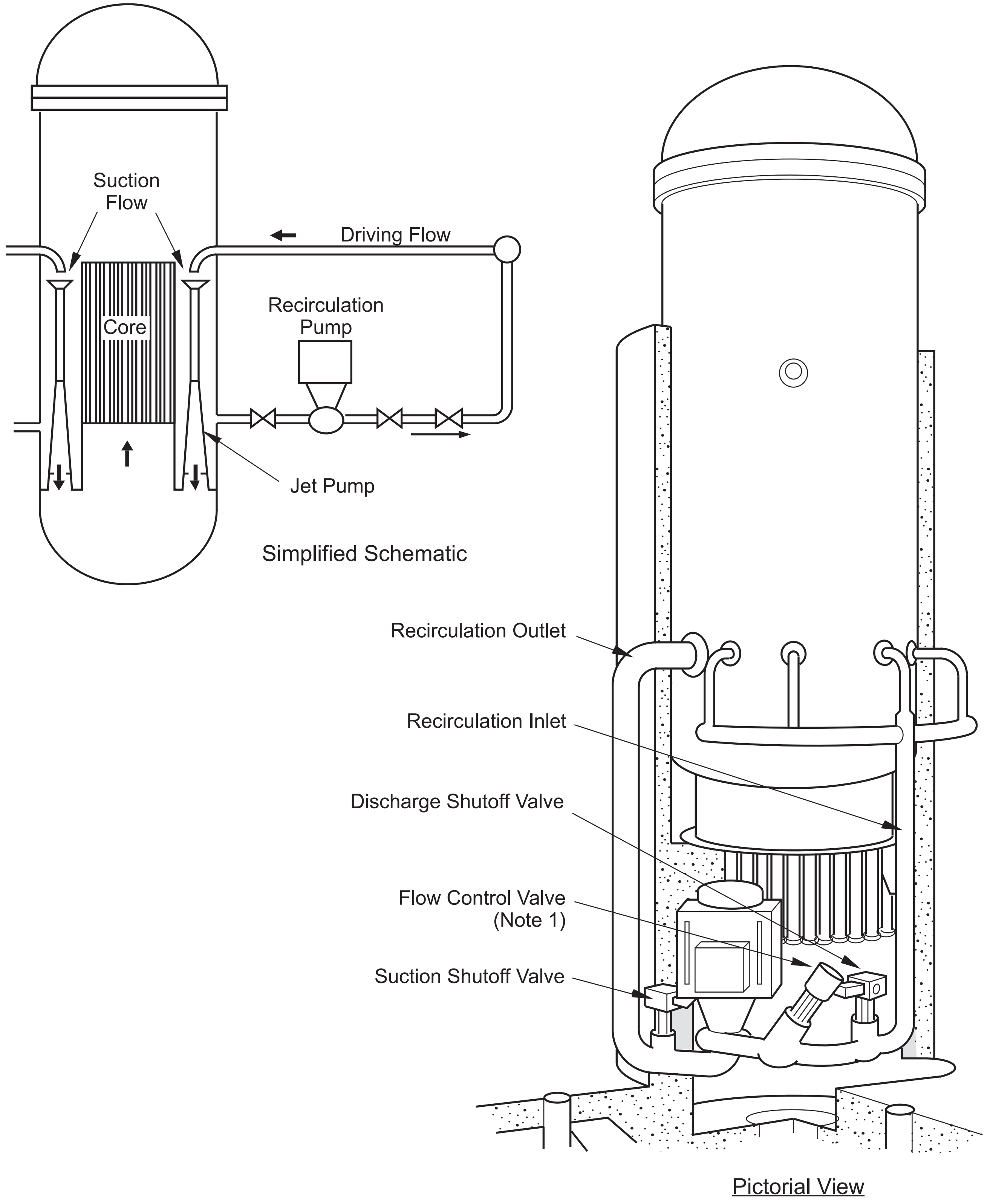
Main steam line safety/relief valves	MS-RV-1A (B22F013J-N) MS-RV-1B (B22F013A-H) MS-RV-1C (B22F013J-N) MS-RV-1D (B22F013J-N) MS-RV-2A (B22F013A-H) MS-RV-2B (B22F013A-H) MS-RV-2C (B22F013A-H) MS-RV-2D (B22F013A-H) MS-RV-3A (B22F013A-H) MS-RV-3B (B22F013A-H) MS-RV-3C (B22F013A-H) MS-RV-3D (B22F013U-V) MS-RV-4A (B22F013R-S) MS-RV-4B (B22F013R-S) MS-RV-4C (B22F013J-N) MS-RV-4D (B22F013P) MS-RV-5B (B22F013U-V) MS-RV-5C (B22F013J-N)
RCIC system discharge line	RCIC-RV-3
RCIC system suction line	RCIC-RV-17 (E51F017)
RCIC lube oil cooler supply line	RCIC-RV-19T
RCIC vacuum tank	RCIC-RV-33 (E51F033)[a]
Shutdown cooling supply line	RHR-RV-5 (E12F005)
Shutdown cooling return line	RHR-RV-25A RHR-RV-25B (F12F025A, B)
Suppression pool supply for RHR	RHR-RV-88A RHR-RV-88B RHR-RV-88C (E12F088A, B, C)
RHR flush line	RHR-RV-30 (E12F030)
RHR heat exchanger (shell side)	RHR-RV-1A RHR-RV-1B
RWCU regenerative heat exchanger (shell side)	RWCU-RV-1

Table 5.4-6

Safety and Relief Valves for Piping Systems
Connected to the Reactor Coolant Pressure Boundary (Continued)

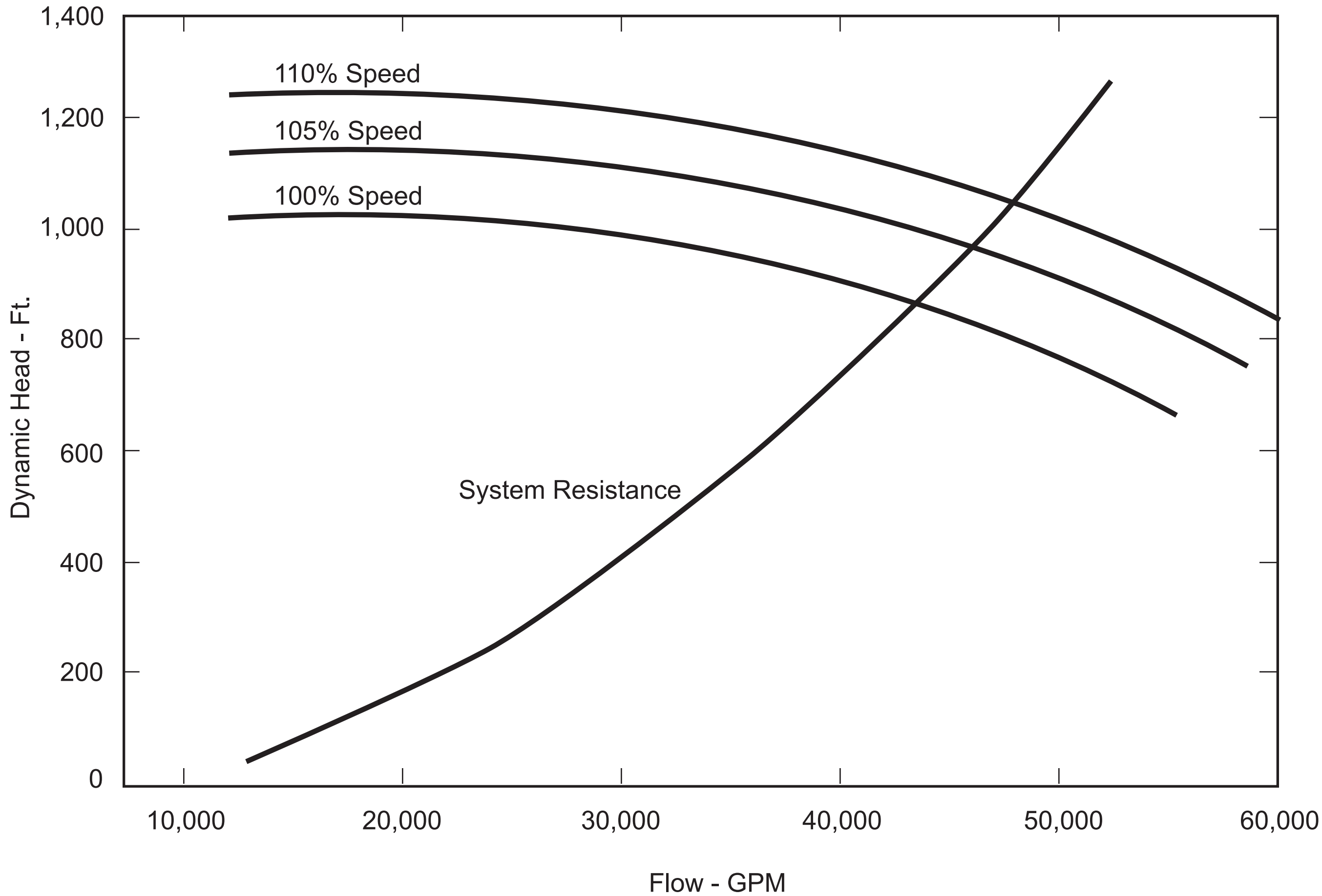
RWCU regenerative heat exchanger (tube side)	RWCU-RV-3
RWCU blowdown to radwaste system or condenser	RWCU-RV-36 (G33F036)
HPCS suction line	HPCS-RV-14 (E22F014)
HPCS discharge line	HPCS-RV-35 (E22F035)
LPCS discharge line	LPCS-RV-18 (E21F018)
LPCS suction line	LPCS-RV-31 (E21F031)
SLC pump discharge line	SLC-RV-29A SLC-RV-29B (C41F029A, B)

[a] These relief valves are installed in a B31.1 system; not subject to Section XI testing and inspection.



Note 1: FCVs Are Mechanically Blocked Full Open.

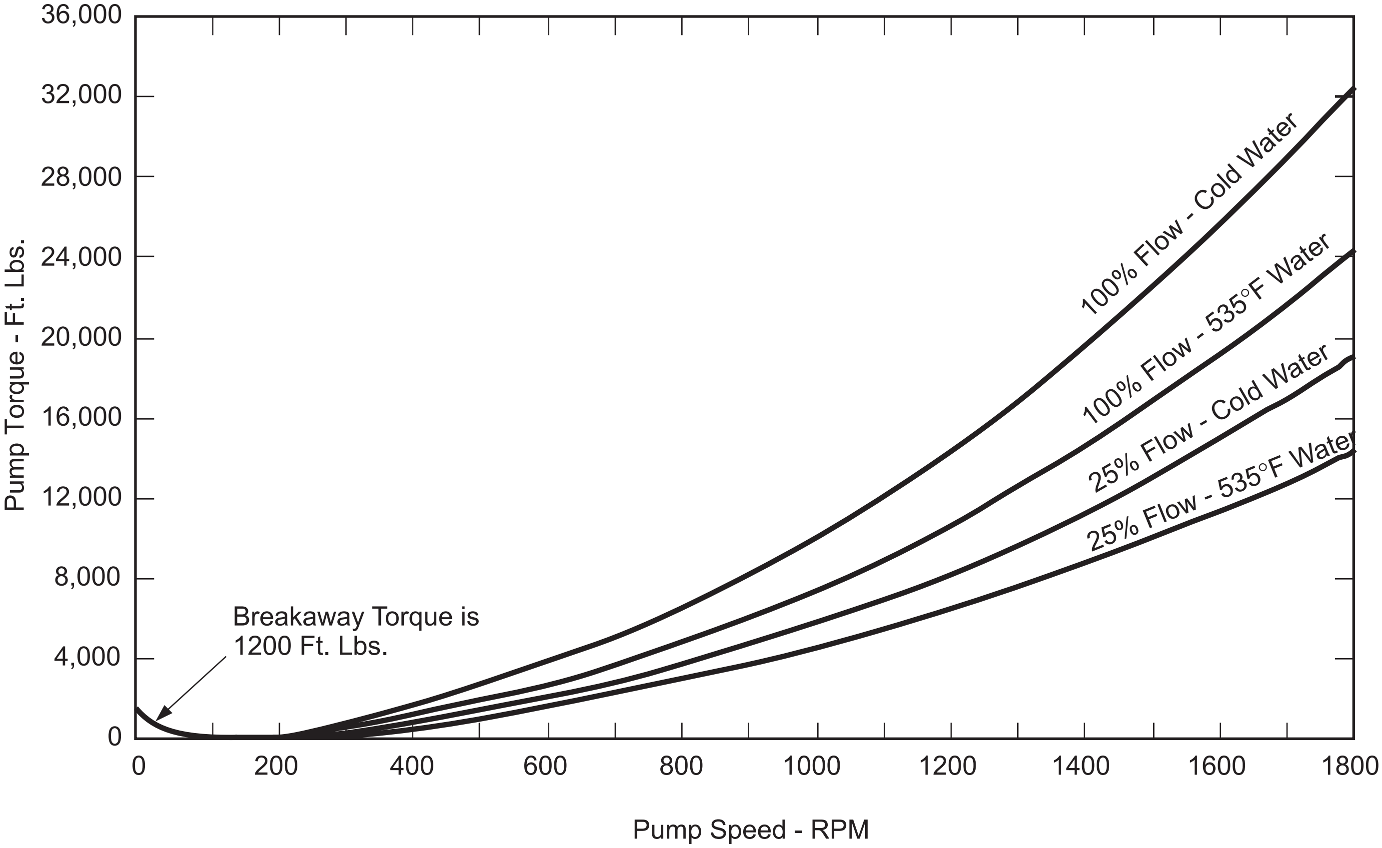
Columbia Generating Station **Final Safety Analysis Report**	**Recirculation System Evaluation and Isometric**
	Draw. No. **960690.07** | Rev. | Figure **5.4-1**



Columbia Generating Station
Final Safety Analysis Report

RRC Pump Dynamic Head-Flow Curve

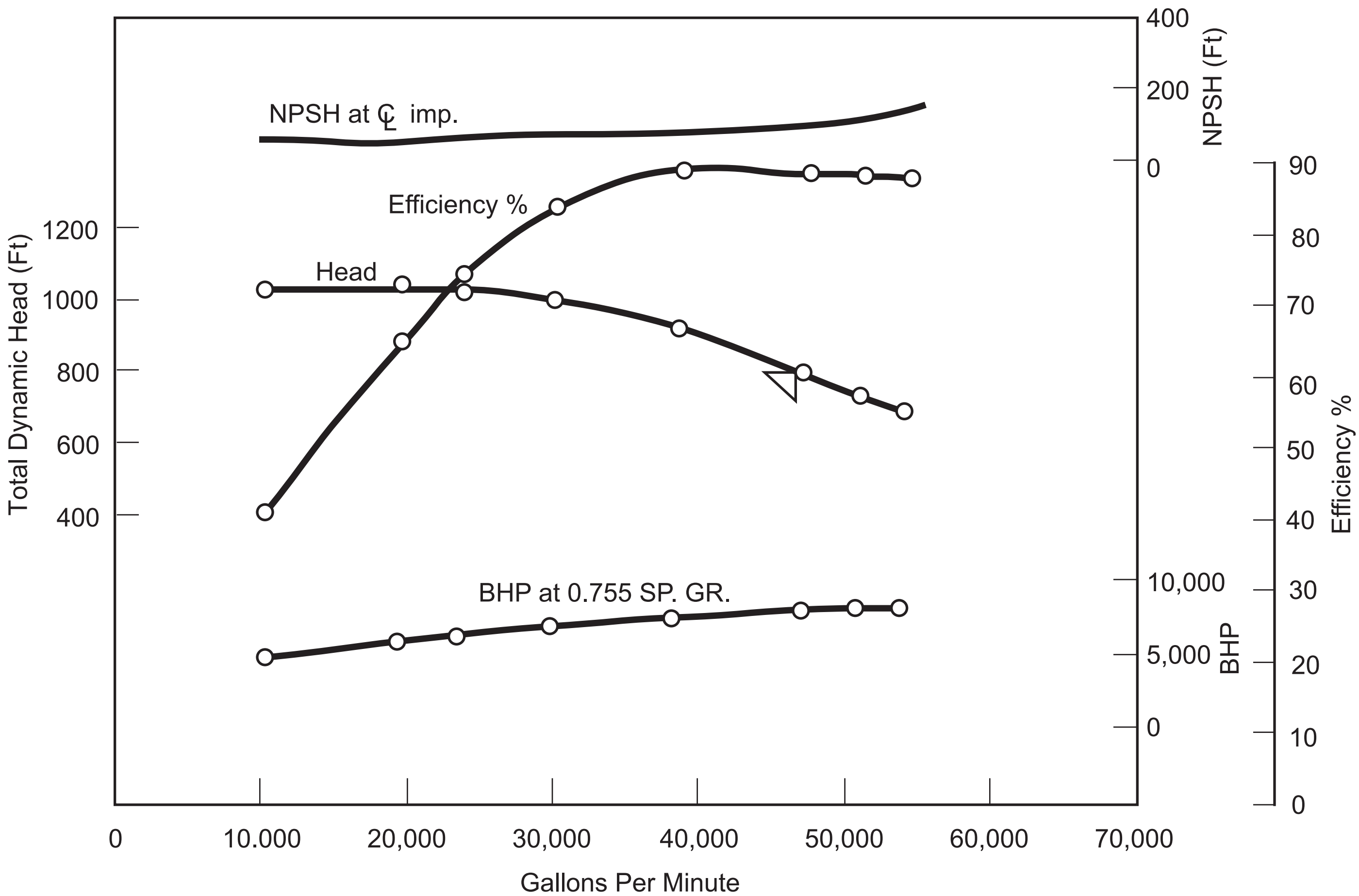
Draw. No. 960690.05	Rev.	Figure 5.4-2



Columbia Generating Station
Final Safety Analysis Report

RRC Pump Speed - Torque Curve

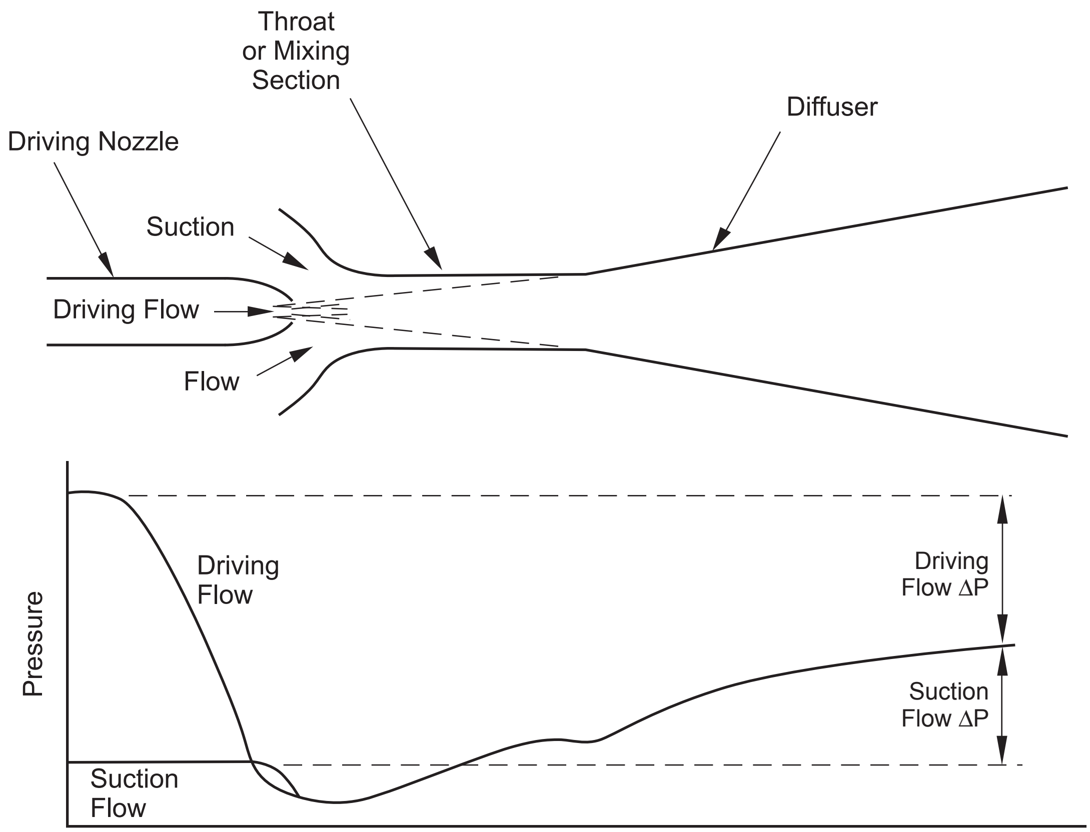
Draw. No. 960690.06	Rev.	Figure 5.4-3



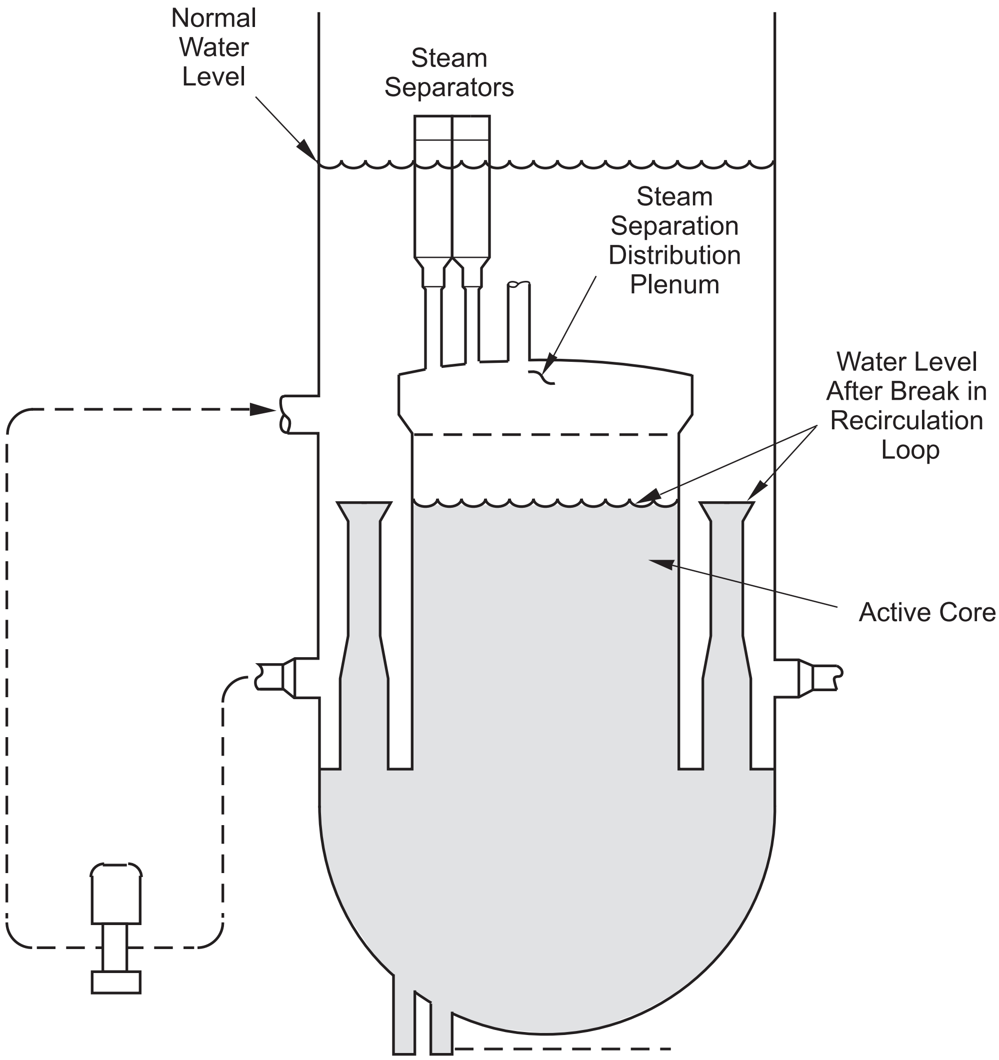
Columbia Generating Station
Final Safety Analysis Report

Recirculation Pump Head,
NPSH, Flow and Efficiency Curves

Draw. No. 960690.59	Rev.	Figure 5.4-4

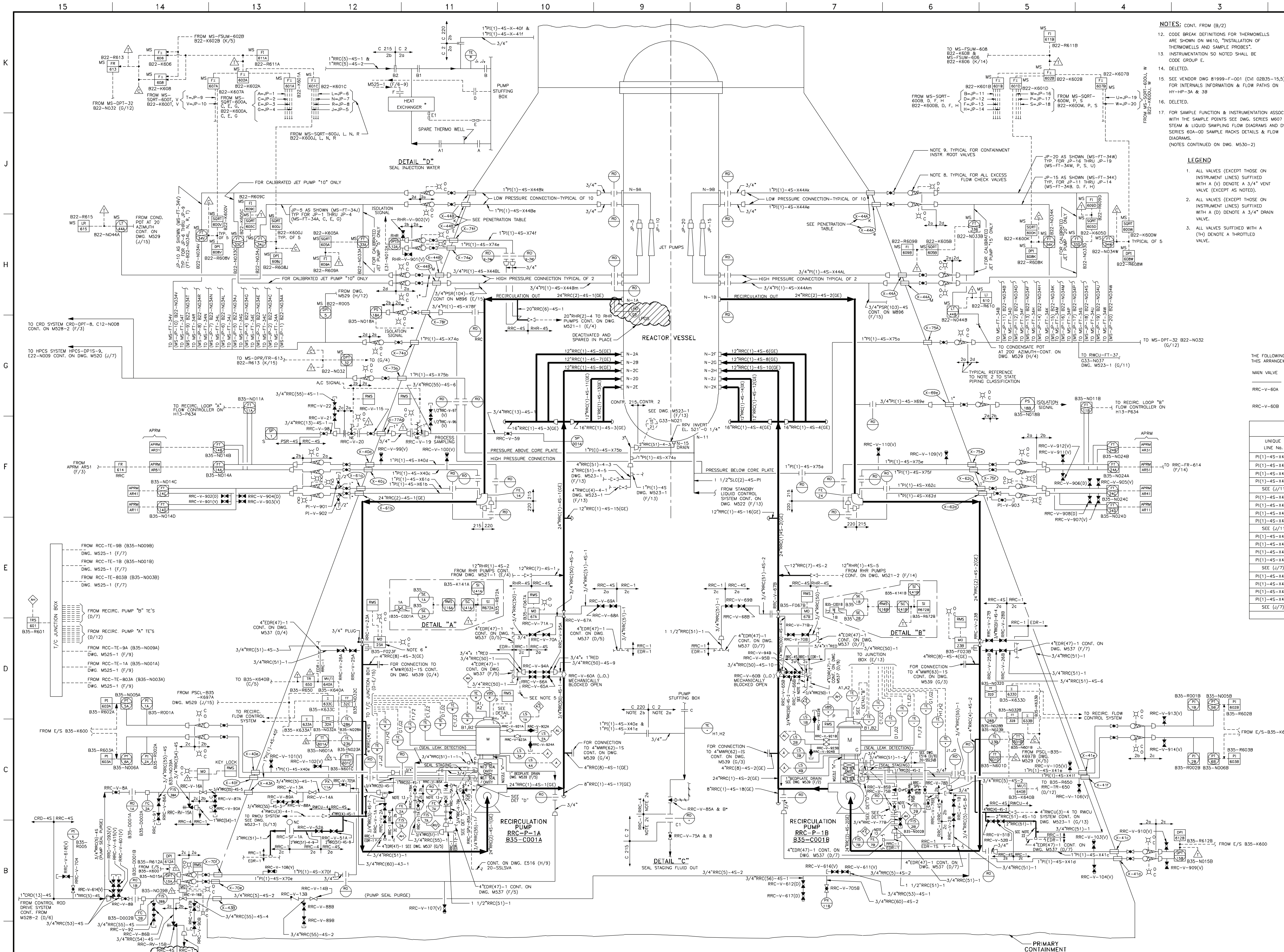


Operating Principle of Jet Pump



Core Flooding Capability of Recirculation System

Draw. No. 960690.60 | Rev. | Figure 5.4-6



NOTES: CONT. FROM (B/2)

12. CODE BREAK DEFINITIONS FOR THERMOWELLS ARE SHOWN ON M610, "INSTALLATION OF THERMOWELLS AND SAMPLE PROBES".
13. INSTRUMENTATION SO NOTED SHALL BE CODE GROUP E.
14. DELETED.
15. SEE VENDOR DWG 81999-F-001 (CVI 02B35-15,5) FOR INTERNALS INFORMATION & FLOW PATHS ON HY-HP-3A & 3B
16. DELETED.
17. FOR SAMPLE FUNCTION & INSTRUMENTATION ASSOCIATED WITH THE SAMPLE POINTS SEE DWG. SERIES M607 STEAM & LIQUID SAMPLING FLOW DIAGRAMS AND DWG. SERIES 60A-00 SAMPLE RACKS DETAILS & FLOW DIAGRAMS.
(NOTES CONTINUED ON DWG. M530-2)

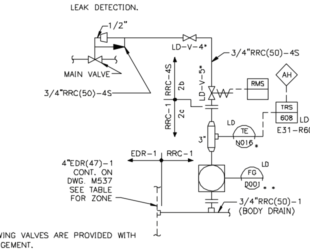
LEGEND

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE (EXCEPT AS NOTED).
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

NOTES:

1. ALL ITEMS MARKED * ARE FURNISHED WITH ASSOCIATED EQUIPMENT.
2. PIPING, VALVES, AND ASSOCIATED COMPONENTS ON THIS DWG. SHALL BE CLASSIFIED AS FOLLOWS (BREAK POINTS ARE INDICATED ON FLOW DIAGRAM):
   a. PIPING AND VALVES OF SUBSYSTEM RRC (1), (2) AND (7) AND INSTRUMENT AND PROCESS PIPING AND VALVES AS NOTED:
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP A
   b. INSTRUMENT AND PROCESS PIPING AND VALVES AS NOTED.
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B
   c. INSTRUMENT AND PROCESS PIPING AND VALVES AS NOTED
      SEISMIC CATEGORY II ⊕
      QUALITY CLASS II } ø
      CODE GROUP D
   d. PUMP SEAL DRAIN LINES AND INSTRUMENT PIPING AS NOTED
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP C

   ⊕ HANGERS TO BE DESIGNED TO SEISMIC CATEGORY I LOADS.
3. ALL INSTRUMENT ROOT VALVES NOT LABELED WILL BE 3/4" GLOBE VALVES UNLESS SPECIFICALLY NOTED OTHERWISE.
4. ALL PIPING SYSTEMS IDENTIFIED BY THE PREFIX "PI" & "PSR" SHALL BE SUPPLIED AND INSTALLED BY CONTRACT #220.
5. DETAIL SHOWS VALVE STEM LEAK-OFF CONNECTION WITH LEAK DETECTION.



THE FOLLOWING VALVES ARE PROVIDED WITH THIS ARRANGEMENT.

MAIN VALVE	*TE AND LEAK-OFF VALVE SUFFIX	**FG SUFFIX	ZONE	UNIQUE LINE No.
RRC-V-60A	G	B-3	(D/10)	3/4"RRC(50)-4S-5
				3/4"RRC(50)-4S-7
RRC-V-60B	H	B-4	(D/8)	3/4"RRC(50)-4S-6
				3/4"RRC(50)-4S-8

JET PUMP TRANSMITTER L.P. SENSING LINE PENETRATION TABLE

UNIQUE LINE No.	PUMP No.	INSTR. PENETR. No.	FT-No.	FT-No.
PI(1)-4S-X44Ba	MS-JP-1	X-44Ba	MS-FT-34A	–
PI(1)-4S-X44Bb	MS-JP-2	X-44Bb	MS-FT-34C	–
PI(1)-4S-X44Bc	MS-JP-3	X-44Bc	MS-FT-34E	–
PI(1)-4S-X44Bd	MS-JP-4	X-44Bd	MS-FT-34G	–
SEE (J/11)	MS-JP-5	X-44Be	MS-FT-34J	MS-FT-33A
PI(1)-4S-X44Bf	MS-JP-6	X-44Bf	MS-FT-34L	–
PI(1)-4S-X44Bg	MS-JP-7	X-44Bg	MS-FT-34N	–
PI(1)-4S-X44Bh	MS-JP-8	X-44Bh	MS-FT-34R	–
PI(1)-4S-X44Bj	MS-JP-9	X-44Bj	MS-FT-34T	–
SEE (J/11)	MS-JP-10	X-44Bk	MS-FT-34V	MS-FT-33C
PI(1)-4S-X44Aa	MS-JP-11	X-44Aa	MS-FT-34B	–
PI(1)-4S-X44Ab	MS-JP-12	X-44Ab	MS-FT-34D	–
PI(1)-4S-X44Ac	MS-JP-13	X-44Ac	MS-FT-34F	–
PI(1)-4S-X44Ad	MS-JP-14	X-44Ad	MS-FT-34H	–
SEE (J/7)	MS-JP-15	X-44Ae	MS-FT-34K	MS-FT-33B
PI(1)-4S-X44Af	MS-JP-16	X-44Af	MS-FT-34M	–
PI(1)-4S-X44Ag	MS-JP-17	X-44Ag	MS-FT-34P	–
PI(1)-4S-X44Ah	MS-JP-18	X-44Ah	MS-FT-34S	–
PI(1)-4S-X44Aj	MS-JP-19	X-44Aj	MS-FT-34U	–
SEE (J/7)	MS-JP-20	X-44Ak	MS-FT-34W	MS-FT-33D

6. THIS EQUIPMENT IS NORMALLY CONTROLLED FROM THE MAIN CONTROL ROOM. IF THE MAIN CONTROL ROOM MUST BE VACATED, THIS CONTROL POINT MAY BE ISOLATED AND CONTROL TRANSFERRED TO THE REMOTE SHUT-DOWN PANEL C61-P001.
7. SEE DWG. M530-2 FOR RRC MISCELLANEOUS SYSTEMS.
8. EXCESS FLOW CHECK VALVES SHALL BE TAGGED AS FOLLOWS:
   PI-EFC-X(PENETRATION NO.)
9. CONTAINMENT INSTRUMENTATION ROOT VALVE SHALL BE TAGGED AS FOLLOWS:
   PI-V-X(PENETRATION NO.)
   øEXCEPT AS NOTED ON M619, INSTRUMENT CONNECTION DIAGRAMS.
10. ALL INSTRUMENTATION ON THIS DRAWING TO BE IDENTIFIED BY PREFIX "RRC" UNLESS SPECIFICALLY NOTED OTHERWISE.
11. ALL INSTR. LINES ARE DESIGNATED BY CODE & LINE #
   A. EXAMPLE: LINES ORIGINATING INSIDE CONTAINMENT
      $\underbrace{\text{1/2" PI(1)-4S}}_{\text{CODE DESIGNATION}}$ – $\underbrace{\text{X106}}_{\text{LINE NUMBER}}$
   B. EXAMPLE: CONTINUATION OF THE ABOVE LINE OUTSIDE CONTAINMENT IS DESIGNATED AS FOLLOWS, WITH LINE NUMBERS NOT SHOWN.
      $\underbrace{\text{1/2"PI(1)-ST-X106}}_{\text{CODE DESIGNATION}}$ – (H22-P021)–
      LINE NUMBER

NOTES CONT. AT ZONE (K/4)

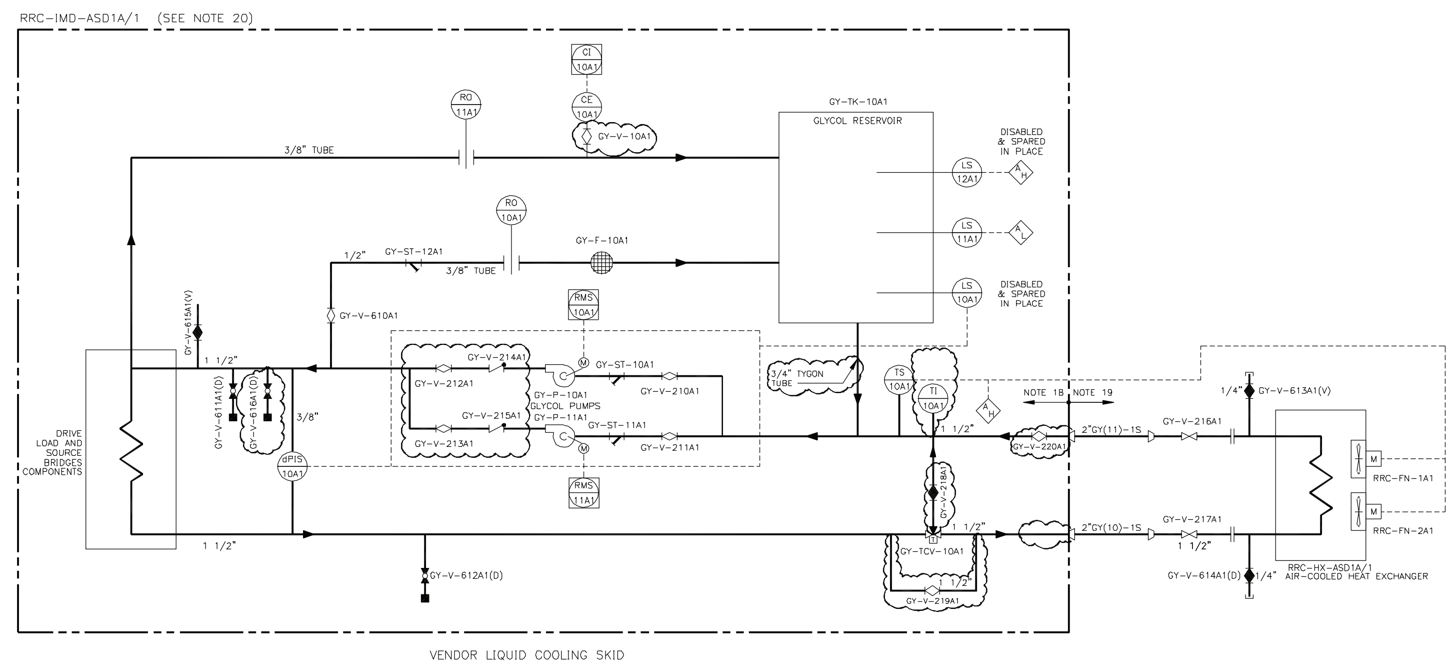
REFERENCES TO CONTRACT NUMBERS, SUCH AS 215, 206, 220, FOUND IN THE NOTES ON THIS DRAWING REFER TO ORIGINAL CONSTRUCTION DESIGN REQUIREMENTS.

CURRENT DESIGN REQUIREMENTS ARE DOCUMENTED IN THE STATION DESIGN SPECIFICATIONS AND ACTIVE CONTRACT SPECIFICATIONS WHICH STILL APPLY.

Columbia Generating Station
Final Safety Analysis Report

Reactor Recirculation System - P&ID

Draw. No. M530-1 | Rev. 94 | Figure 5.4-7.1



INDUCTION MOTOR DRIVES LIQUID COOLING SYSTEM – RRC PUMP ADJUSTABLE SPEED DRIVES
(SEE NOTES 20 & 21)

NOTES: (CONT. FROM M530-1)

18. ALL SYSTEM COMPONENTS, INCLUDING SUPPORTS, PIPING, AND EQUIPMENT REFERRING TO THIS NOTE SHALL BE CLASSIFIED AS FOLLOWS:

    SEISMIC CATEGORY II
    QUALITY CLASS 2

19. PIPING BETWEEN DRIVE COOLING SKID AND HEAT EXCHANGER IS:

    SEISMIC CATEGORY II
    QUALITY CLASS 2
    CODE GROUP D

20. EPN'S SHOWN ARE FOR ONE OF FOUR DRIVE LINEUPS. THE APPLICABLE SUFFIX FOR ALL EPN'S IS AS FOLLOWS:

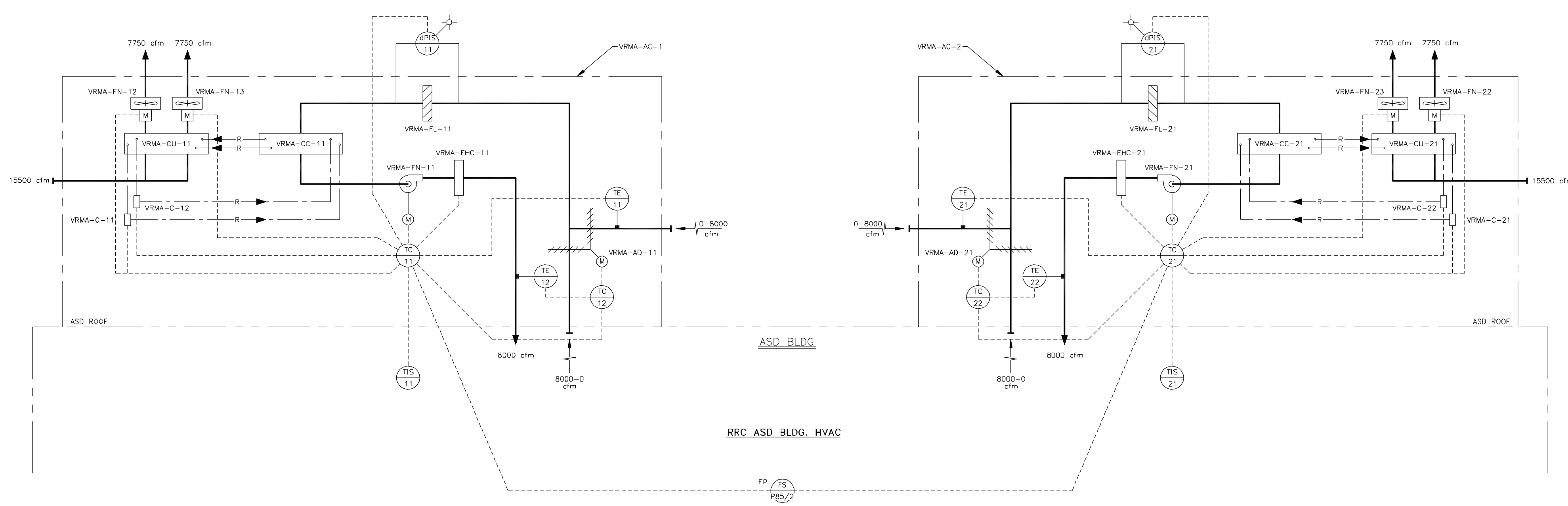
	DRIVE	COMPONENT EPN
SHOWN –	RRC-IMD-ASD1A/1	GY-X-XXA1
	RRC-IMD-ASD1A/2	GY-X-XXA2
	RRC-IMD-ASD1B/1	GY-X-XXB1
	RRC-IMD-ASD1B/2	GY-X-XXB2

21. LIQUID COOLANT IS DISTILLED OR DE-IONIZED WATER AND PURE PROPYLENE GLYCOL. DO NOT USE RUST-INHIBITING GLYCOL SOLUTIONS.

22. PIPING IS BLANKED OFF DOWNSTREAM OF RRC-V-52B AND THAXTON EXPANDABLE PLUG IS INSTALLED BETWEEN VALVE AND PLATE.

23. DELETED

24. SEE DWG M501 FOR FLOW DIAGRAM LEGENDS, SYMBOLS AND ABBREVIATIONS.

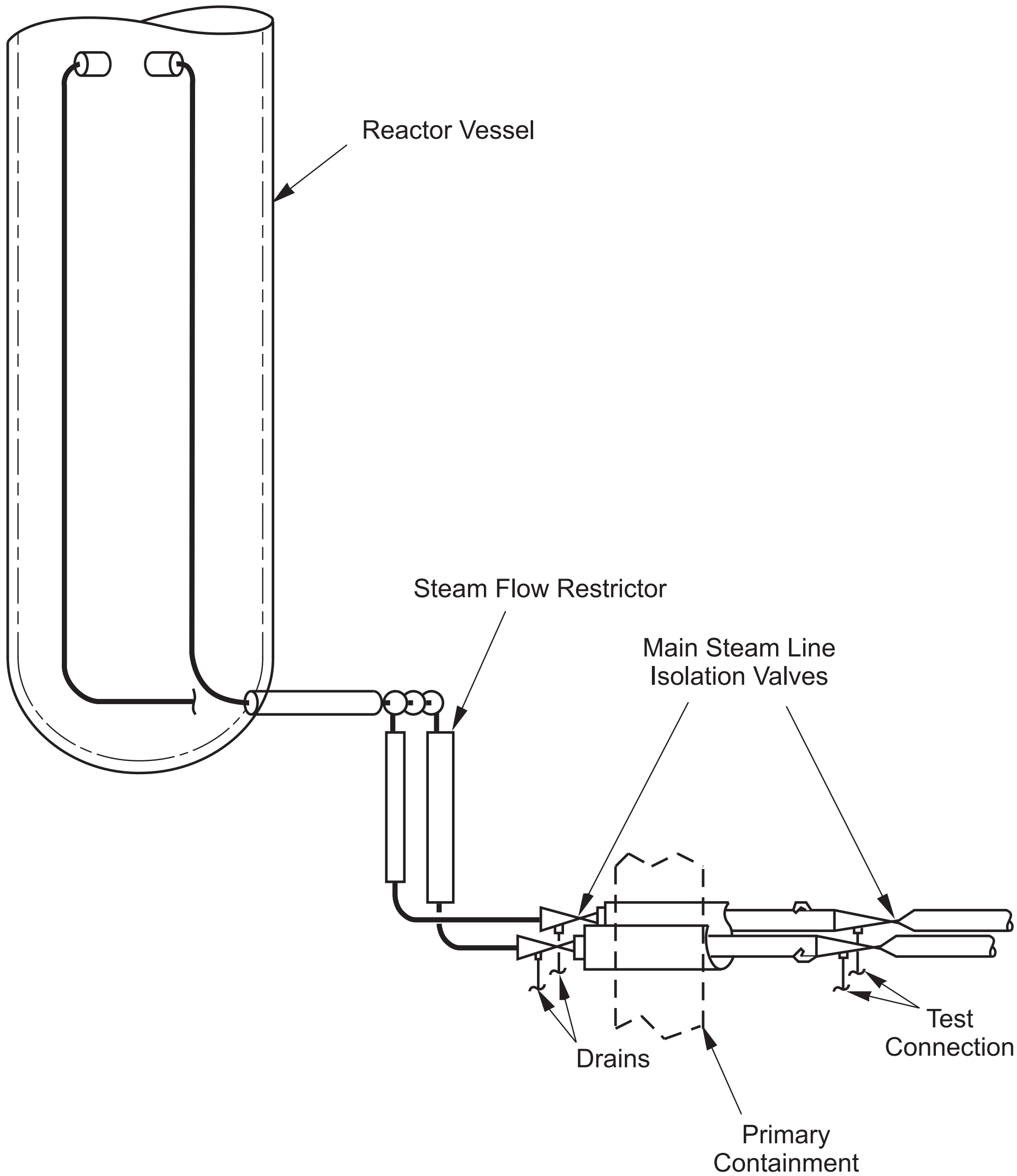


RRC ASD BLDG. HVAC

Columbia Generating Station
Final Safety Analysis Report

Reactor Recirculation System - P&ID

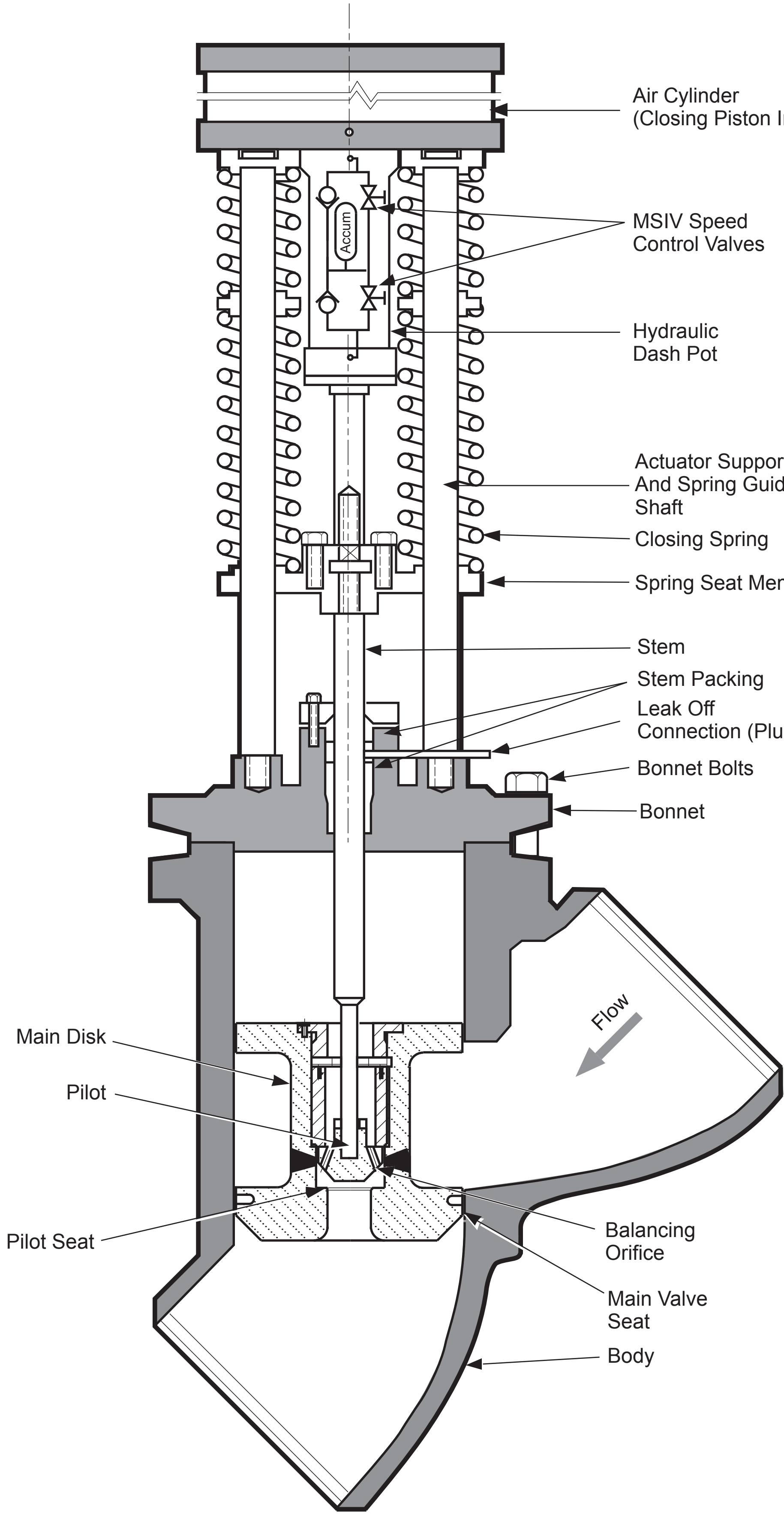
Draw. No. M530-2	Rev. 13	Figure 5.4-7.2



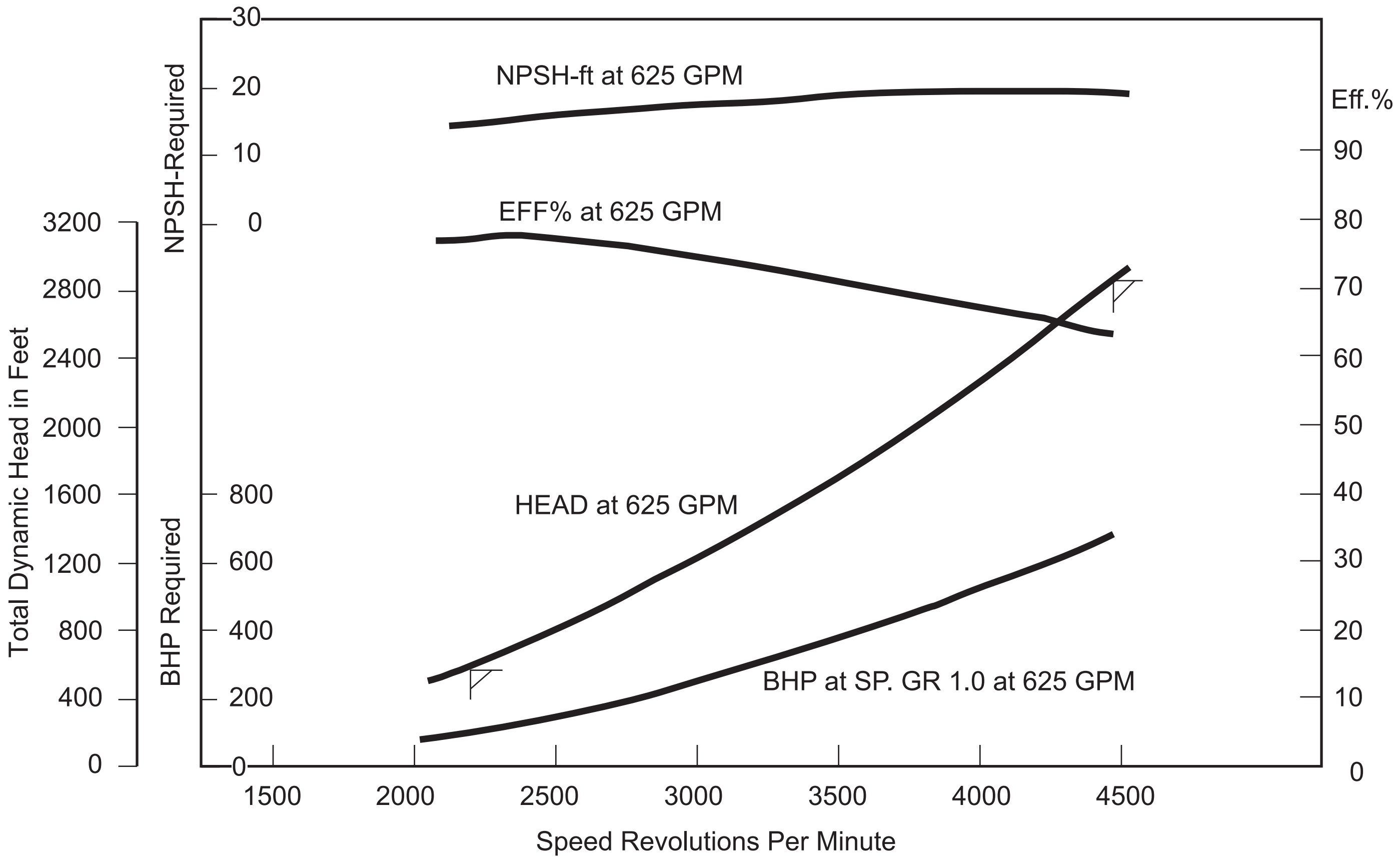
Columbia Generating Station
Final Safety Analysis Report

Main Steam Line Flow Restrictor Location

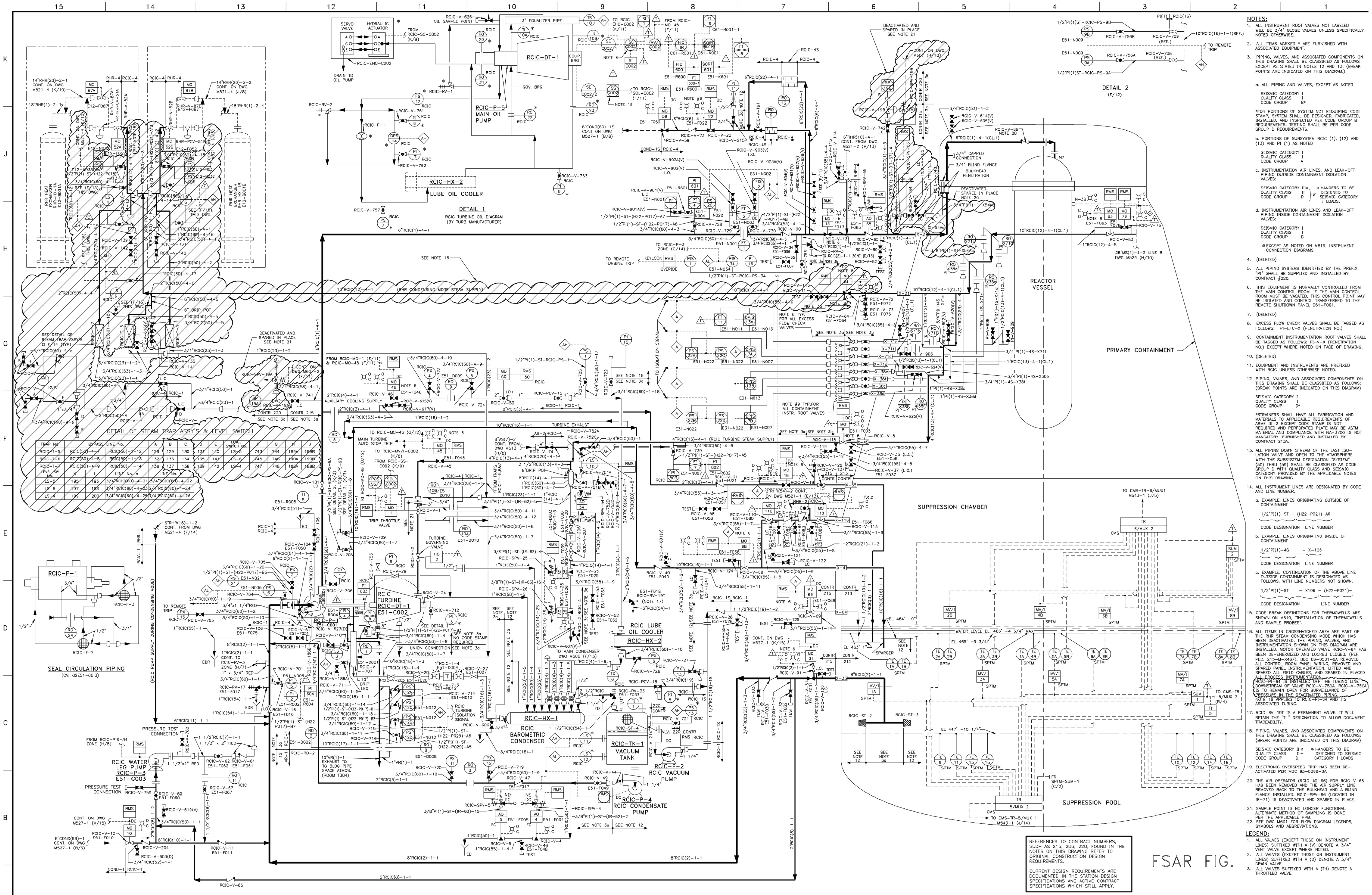
Draw. No. 960690.61 | Rev. | Figure 5.4-8



Columbia Generating Station **Final Safety Analysis Report**	**Main Steam Line Isolation Valve**
	Draw. No. **960690.84** | Rev. | Figure **5.4-9**



Witness Test Performance
Bingham-Willamette Co.
Portland, Oregon



Columbia Generating Station
Final Safety Analysis Report

RCIC System - P&ID

Draw. No. M519	Rev. 101	Figure 5.4-11

(SEE NOTE 12 & 13)

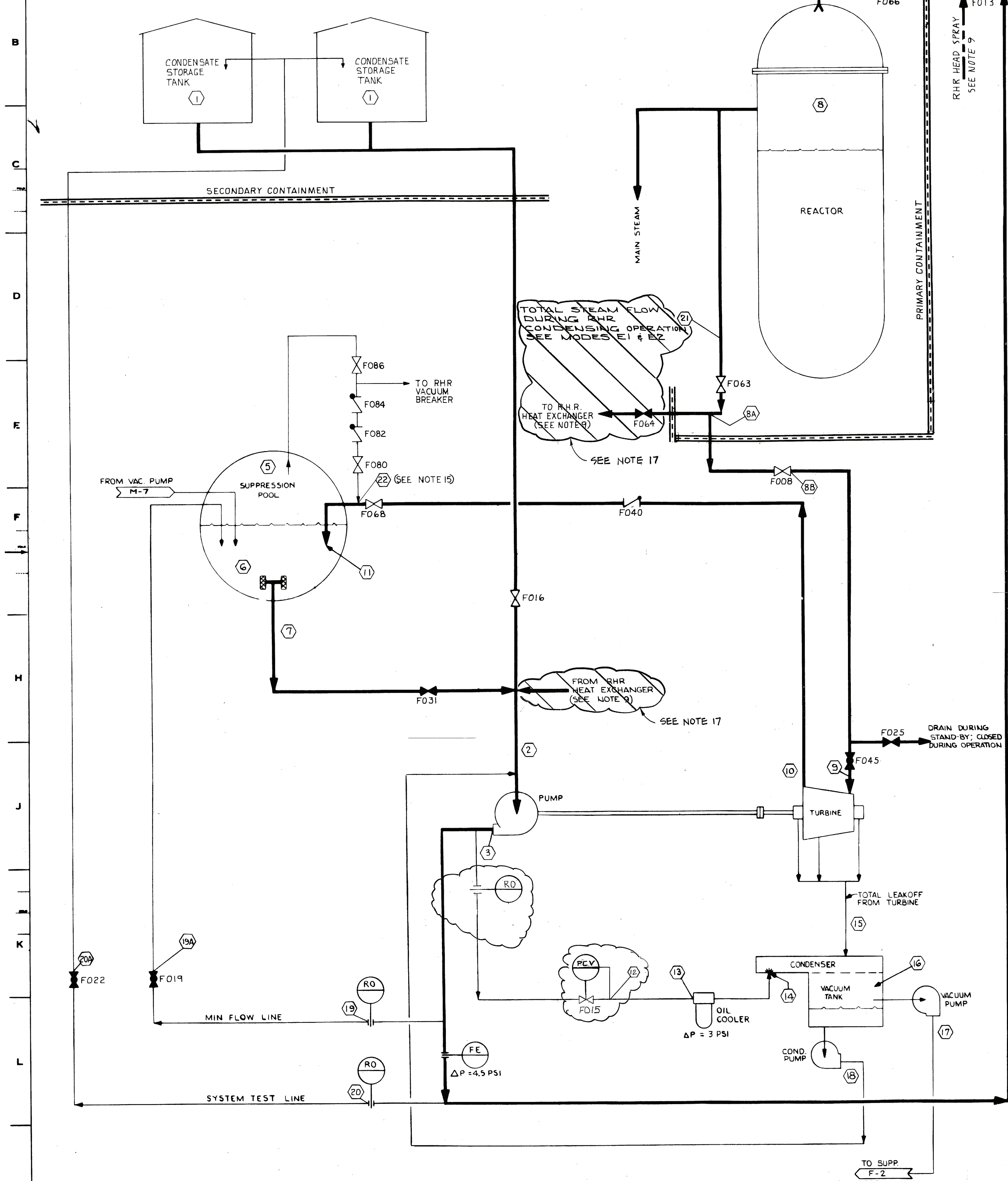
LOCATION ⬡	1-2	3-3A	3A-4	7-2	8-8A	8A-9	3-12	12-13	13-14	15	17	18-2	19-19A	19A-6	20-20A	20A-1	10-11
PEAK PRESSURE PSIG	N/A	1481	1481	N/A	1337	1337	1481	N/A	N/A	N/A	N/A	N/A	1481	N/A	1481	N/A	160
RECOMMENDED DESIGN PRESSURE	100	1500	1500	100	1250	1250	1500	100	100	75	75	100	1500	100	1500	100	150
DESIGN TEMPERATURE °F	170	170	575	170	575	575	170	170	170	250	190	190	170	170	170	170	267
ESTIMATED LINE SIZE, IN.	6	6	6	6	10	4	2	2	2	1	1¼	2	2	2	4	4	10

15. MAXIMUM LINEAR LENGTH BETWEEN POSITIONS 5 AND 22 EQUALS 60 FEET. THE INTERNAL CROSS-SECTIONAL AREA OF THE VACUUM BREAKER PIPING THAT IS SHARED BY THE RCIC AND RHR SHALL BE EQUAL TO OR GREATER THAN THE COMBINED INTERNAL CROSS-SECTIONAL AREAS OF THE INDIVIDUAL RCIC AND RHR VACUUM BREAKER LINES.

16. STEAM FLOWS FOR TEST MODE F AT POSITION 9, 10 AND 11 ARE BASED UPON A PUMP TDH OF 2490 FEET.

17. RHR STEAM CONDENSING MODE HAS BEEN DEACTIVATED.

~~18. ONLY HIGH PRESSURE MODES WERE REVISED FOR RPU. MODES B&D WOULD NOT BE SIGNIFICANTLY AFFECTED.~~



12. DESIGN PRESSURES AND TEMPERATURES GIVEN ARE THE BASIS FOR DESIGN OF GE SUPPLIED EQUIPMENT. ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL LINE SIZES AS DETERMINED BY PIPING DESIGNER, SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENTS.

13. "PEAK PRESSURE" IS THE MAXIMUM PRESSURE ANTICIPATED DURING A TRANSIENT PERIOD WITH ALL OF THE CONTRIBUTING ELEMENTS AT A MAXIMUM. IT WOULD BE EXPECTED TO OCCUR LESS THAN 1% OF SYSTEM OPERATING TIME.

14. FLOW VALUES SHOWN IN MODES C & D ARE BASED UPON SUCTION PIPING DESIGN PERMITTING THE MINIMUM REQUIRED NPSH TO CONTINUE TO BE PROVIDED TO THE RCIC PUMP WHEN THE SUPPRESSION POOL SUCTION STRAINER IS 50% PLUGGED.

✱ THE PRESSURE AT THIS LOCATION DEPENDS ON PIPING ARRANGEMENT, AND MAY BE VARIED WITHIN THE FOLLOWING LIMITS.

LOCATION

- 2 MINIMUM NPSH AT PUMP SUCTION = 21 FEET
- 3 MAXIMUM PUMP TOTAL DYNAMIC HEAD 3016 FEET FOR MODES A & C, 610 FEET FOR MODES B & D
- 9 MAXIMUM PRESSURE DROP BETWEEN LOCATION 8 AND 9 = 15 PSI (SEE NOTE 6)
- 10 MAXIMUM PRESSURE ALLOWED = 25 PSIA
- 13 MAXIMUM PRESSURE ALLOWED = 75 PSIA
- 15 SUFFICIENT VACUUM TO PREVENT TURBINE SHAFT-OUT-LEAKAGE.
- 17 MAXIMUM PRESSURE AVAILABLE = 25 PSIA
- 18 MAXIMUM PRESSURE AVAILABLE = 65 PSIA
- 19 SUFFICIENT PRESSURE TO RETURN TO SUPPRESSION POOL
- 20 SUFFICIENT PRESSURE TO RETURN TO COND. STORAGE

NOTES:

MPL ITEM Nº : E51-1020

1. ATMOSPHERIC PRESSURE OF 14.7 PSIA WAS USED IN CALCULATIONS.
2. WATER FLOWS ARE SHOWN ~~IN GPM,~~ STEAM FLOWS IN 1000 LB/HR.
3. THE MAXIMUM POOL WATER TEMPERATURE FOR CONTINUOUS SYSTEM OPERATION WILL NOT EXCEED 140°F. HOWEVER, DUE TO POTENTIAL SHORT TERM OPERATION AT HIGHER TEMPERATURES, PIPING EXPANSION SHALL BE BASED ON 170°F.
4. THE UNRECOVERED FLOW NOZZLE PRESSURE DROP OF 4.5 PSI IS A FIXED LOSS BETWEEN LOCATIONS 3 AND 4
5. THE LUBE OIL COOLER PRESSURE DROP OF 3.0 PSI IS A FIXED LOSS BETWEEN LOCATIONS 13 AND 14
6. THE CONTROLLING MODES FOR LINE SIZING AND ARRANGEMENT ARE:
   - SUCTION FROM COND STORAGE - - - - - - - - - - - - MODE A & B
   - SUCTION FROM SUPPRESSION POOL - - - - - - - - - - - MODE C & D
   - PUMP DISCHARGE- - - - - - - - - - - - - - - - - - MODE C & D
   - STEAM SUPPLY- - - - - - - - - - - - - - - - - - - MODE A & B
   - TURBINE EXHAUST - - - - - - - - - - - - - - - - - - MODE A & C
   - TEST LINE - MODE F
   - COOLING SYSTEM- - - - - - - - - - - - - - - - - - MODE A
7. SYSTEM OPERATION IS POSSIBLE WITH INTERMEDIATE PRESSURES IN THE REACTOR VESSEL AND THE SUPPRESSION POOL. HOWEVER, THESE CONDITIONS DO NOT CONTROL PIPE OR VALVE SIZING OR SPECIFICATION, AND NO DATA IS SHOWN.
8. PUMP MINIMUM FLOW REQUIREMENT MAY OCCUR DURING ANY OPERATING MODE. FLOW REQUIREMENT IS 75 GPM MINIMUM.
9. FOR VALVE AND FLOW INFORMATION, REFER TO THE RHR SYSTEM P&ID MPL E12-1010 AND PROCESS DIAGRAM MPL E12-1020.
10. DURING SYSTEM STANDBY, EQUIPMENT IS NOT OPERATING. INTERMITTENT FLOW OCCURS THROUGH THE STEAM SUPPLY LINE DRAIN TRAP SYSTEM AT 1000 PSIA AND 560°F.
11. HEAD SPRAY NOZZLE PRESSURE DROP IS 10 PSI.

MODE A — SUCTION FROM CONDENSATE STORAGE, REACTOR AT HIGH PRESSURE, SUPPRESSION POOL AT HIGH PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FLOW-SEE NOTE 2	—	600	625	600	—	—	0	—	30.73	30.57	30.57	25	25	25	0.15	—	0.01	25+	—	0
OPERATING PRESSURE-PSIA	14.7	✱	✱	1235	18	—	—	1225	✱	✱	19.9	75	✱	45	✱	9.8	✱	✱	✱	—
EXPECTED TEMPERATURE °F	100	100	100	100	110	—	—	565	SAT	SAT	228	100	100	100	230	120	120	120	100	—
MAX/MIN TEMPERATURE °F	100/40	100/40	100/40	100/40	170/40	—	—	570/70	570/70	250/70	250/70	100/40	100/40	100/40	250/40	120/40	120/40	120/40	100/40	—

MODE B — SUCTION FROM CONDENSATE STORAGE, REACTOR AT LOW PRESSURE, SUPPRESSION POOL AT HIGH PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FLOW-SEE NOTE 2	—	600	616	600	—	—	0	—	9.30	9.15	9.15	16	16	16	0.15	—	0.01	16+	—	0
OPERATING PRESSURE-PSIA	14.7	✱	✱	178	18	—	—	165	✱	✱	19.8	75	✱	45	✱	9.8	✱	✱	✱	—
EXPECTED TEMPERATURE °F	100	100	100	100	140	—	—	366	SAT.	SAT.	227	100	100	100	230	120	120	120	100	—
MAX/MIN TEMPERATURE °F	100/40	100/40	100/40	100/40	170/40	—	—	366/70	366/70	250/70	250/70	100/40	100/40	100/40	250/40	120/40	120/40	120/40	100/40	—

MODE C — SUCTION FROM SUPPRESSION POOL, REACTOR AT HIGH PRESSURE, SUPPRESSION POOL AT LOW PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FLOW-SEE NOTE 2	—	600	625	600	—	—	600	—	29.82	29.66	29.66	25	25	25	0.15	—	0.01	25+	—	0
OPERATING PRESSURE-PSIA	—	✱	✱	1235	14.7	19.2	18.8	1225	✱	✱	16.6	75	✱	45	✱	9.8	✱	✱	✱	—
EXPECTED TEMPERATURE °F	—	140	140	140	140	140	140	565	SAT.	SAT.	218	140	140	140	230	160	160	160	140	—
MAX/MIN TEMPERATURE °F	—	170/40	170/40	170/40	170/40	170/40	170/40	570/70	570/70	250/70	250/70	170/40	170/40	170/40	250/40	190/40	190/40	190/40	170/40	—

MODE D — SUCTION FROM SUPPRESSION POOL, REACTOR AT LOW PRESSURE, SUPPRESSION POOL AT LOW PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FLOW-SEE NOTE 2	—	600	616	600	—	—	600	—	8.40	8.25	8.25	16	16	16	0.15	—	0.01	16+	—	0
OPERATING PRESSURE-PSIA	—	✱	✱	178	14.7	19.2	18.8	165	✱	✱	16.5	75	✱	45	✱	9.8	✱	✱	✱	—
EXPECTED TEMPERATURE °F	—	140	140	140	140	140	140	366	SAT.	SAT.	218	140	140	140	230	160	160	160	140	—
MAX/MIN TEMPERATURE °F	—	170/40	170/40	170/40	170/40	170/40	170/40	366/70	366/70	250/70	250/70	170/40	170/40	170/40	250/40	190/40	190/40	190/40	170/40	—

SEE NOTE 17
MODE. E-1 — SUCTION FROM RHR HEAT EXCHANGERS, REACTOR AT HIGH PRESS., SUPPRESS. POOL AT LOW PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
FLOW-SEE NOTE 2	—	380	396	380	—	—	0	—	20.15	20.00	20.00	16	16	16	0.15	—	0.01	16+	—	0	207.3
OPERATING PRESSURE-PSIA	—	✱	✱	1025	14.7	—	—	1015	✱	✱	16.6	75	✱	45	✱	9.8	✱	✱	✱	—	1015
EXPECTED TEMPERATURE °F	—	140	140	140	140	—	—	560	SAT.	SAT.	218	140	140	140	230	160	160	160	140	—	560
MAX/MIN TEMPERATURE °F	100/40	170/40	170/40	170/40	170/40	—	—	560/70	560/70	250/70	250/70	170/40	170/40	170/40	250/40	190/40	190/40	190/40	170/40	—	560/70

SEE NOTE 17
MODE E-2 — SUCTION FROM RHR HEAT EXCHANGERS, REACTOR AT LOW PRESS, SUPPRESS. POOL AT LOW PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
FLOW-SEE NOTE 2	—	215	231	215	—	—	0	—	5.15	5.00	5.00	16	16	16	0.15	—	0.01	16+	—	0	119.6
OPERATING PRESSURE-PSIA	—	✱	✱	163	14.7	—	—	150	✱	✱	16.6	75	✱	45	✱	9.8	✱	✱	✱	—	150
EXPECTED TEMPERATURE °F	—	140	140	140	140	—	—	358	SAT.	SAT.	218	140	140	140	230	160	160	160	140	—	358
MAX/MIN TEMPERATURE °F	100/40	170/40	170/40	170/40	170/40	—	—	358/70	560/70	250/70	250/70	170/40	170/40	170/40	250/40	190/40	190/40	190/40	170/40	—	358/70

F

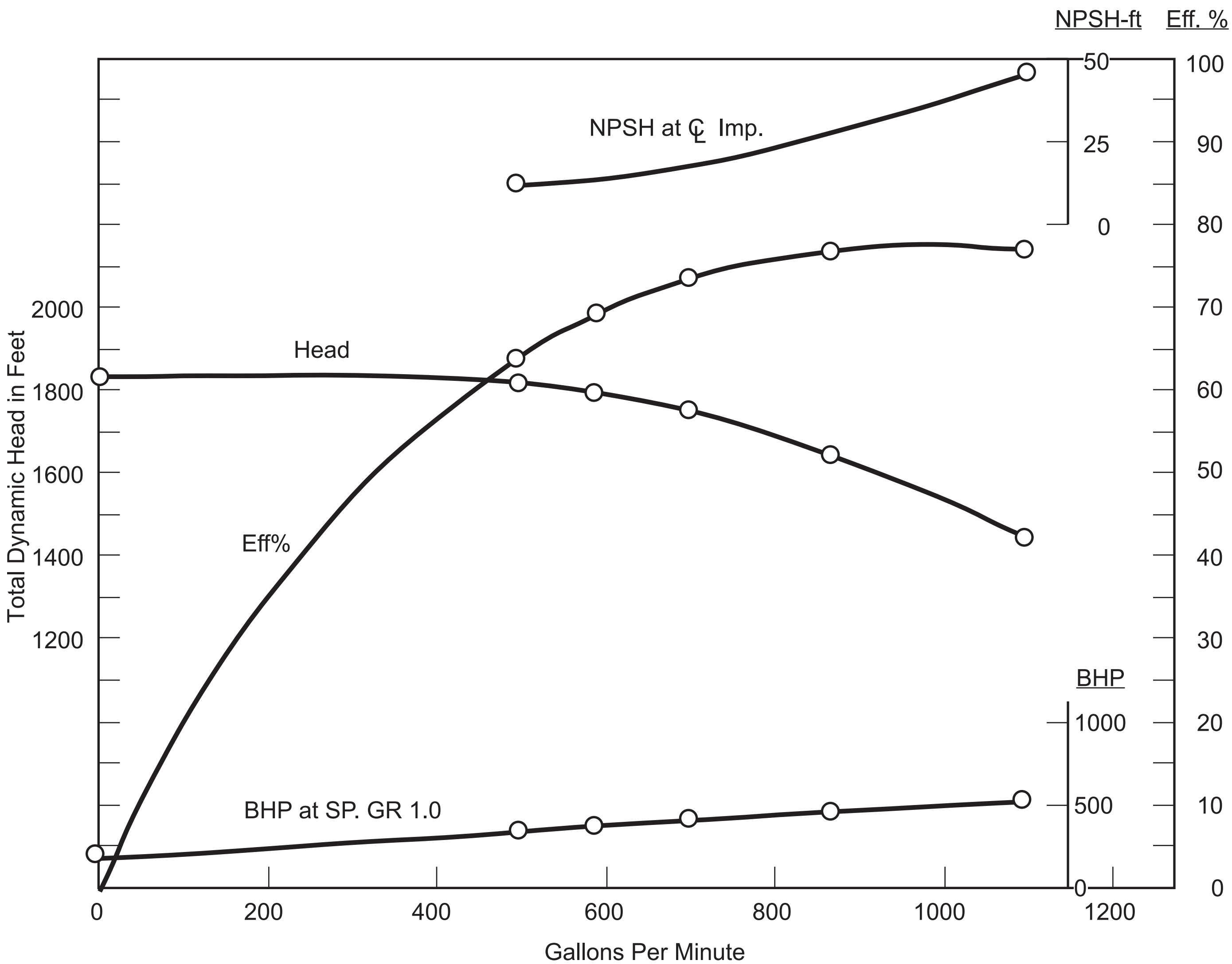
MODE F — TEST MODE: SUCTION FROM CONDENSATE STORAGE, REACTOR AT HIGH PRESS., SUPPRESS POOL AT LOW PRESS.

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FLOW-SEE NOTE 2	—	600	616	—	—	—	0	—	23.50	23.35	23.35	16	16	16	0.15	—	0.01	16+	—	600
OPERATING PRESSURE-PSIA	14.7	✱	✱	—	14.7	—	—	1000	✱	✱	16.6	75	✱	45	✱	9.8	✱	✱	✱	✱
EXPECTED TEMPERATURE °F	100	100	100	—	100	—	—	545	SAT.	SAT.	218	100	100	100	230	120	120	120	100	100
MAX/MIN TEMPERATURE °F	100/40	100/40	100/40	—	170/40	—	—	545/70	545/70	250/70	250/70	100/40	100/40	100/40	250/40	120/40	120/40	120/40	100/40	100/40

Columbia Generating Station
Final Safety Analysis Report

RCIC System Process Diagram

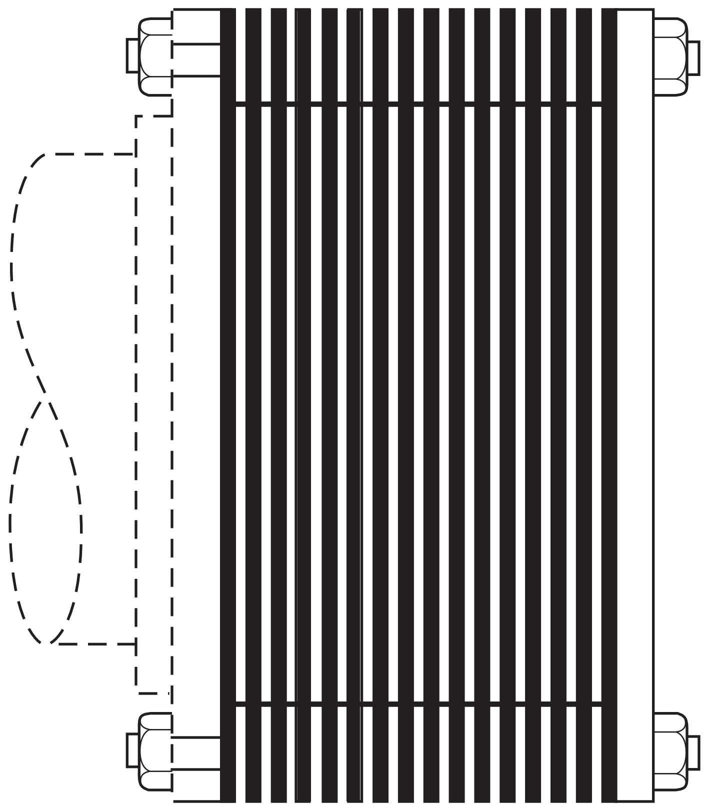
Draw. No. 02E51-04,4,1 | Rev. 10 | Figure 5.4-12



Test Speed RG. 3591-3585 RPM

Whitness Test Performance
Bingham-Willamette Co.
Portland, Oregon.

Measurements for Strainers at
Penetration X-33
Rated Flow: 600 gal/min



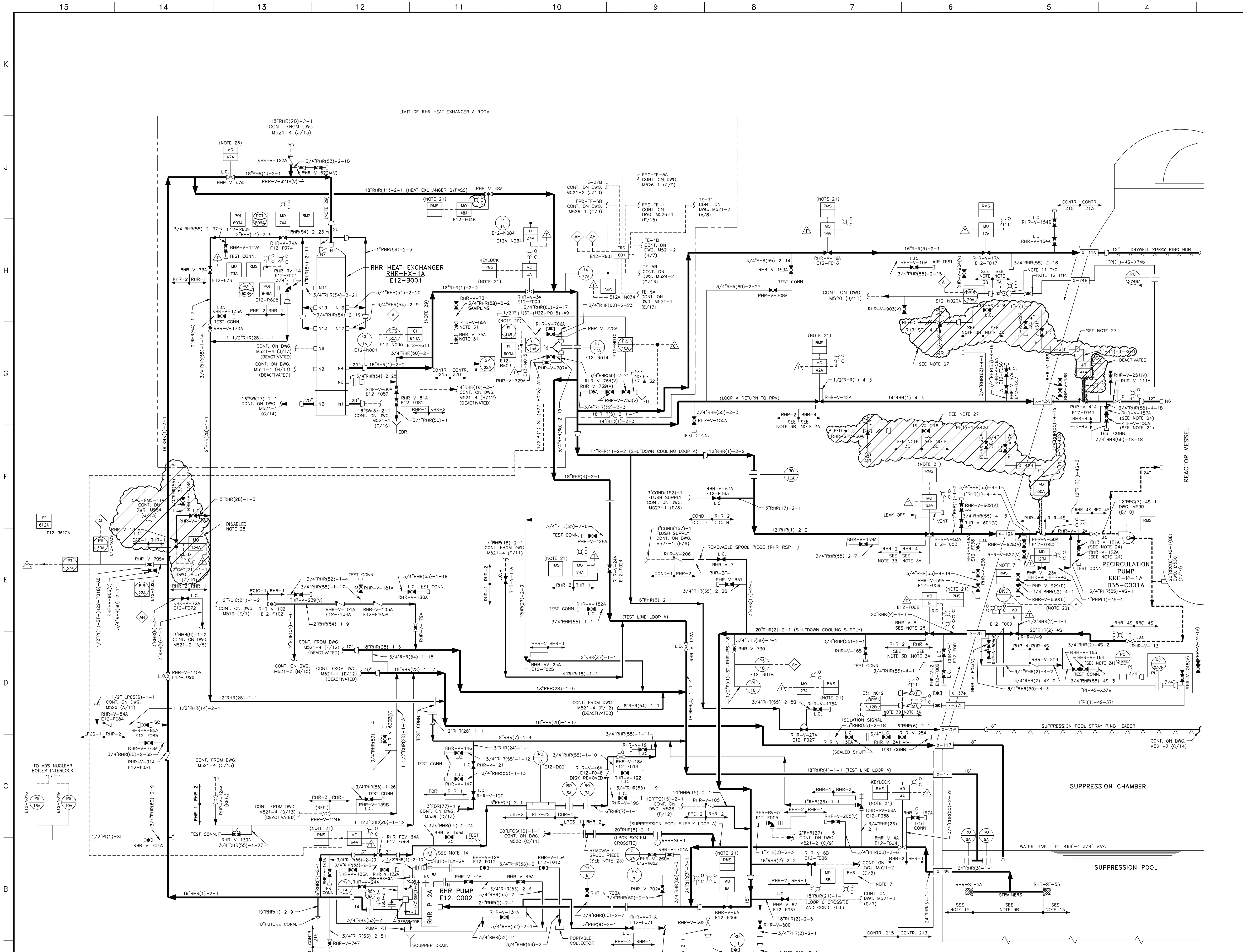
Notes:

1. Flow stated above is per penetration with two (2) units described above required per penetration.

2. Units are designed, manufactured and inspected in accordance with ASME Section III, Class 2 (not stamped) 1974 Ed. with Addenda thru Winter 1976.

3. Design temp: 220°F

Columbia Generating Station Final Safety Analysis Report	Typical Strainer
	Draw. No. 960690.87 | Rev. | Figure 5.4-14



NOTES:

1. ALL PRESSURE & FLOW INSTRUMENT ROOT VALVES NOT LABELLED WILL BE 3/4" GLOBE VALVES (UNLESS SPECIFICALLY NOTED OTHERWISE).
2. ALL ITEMS MARKED * ARE FURNISHED WITH ASSOCIATED EQUIPMENT.
3. PIPING, VALVES, AND ASSOCIATED COMPONENTS ON THIS DWG. SHALL BE CLASSIFIED AS FOLLOWS, EXCEPT AS STATED IN NOTES 15 & 17 (BREAK POINTS ARE INDICATED ON FLOW DIAGRAM):
   A. PIPING AND VALVES OUT THROUGH OUTERMOST REAC. ISOL. VALVES:
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP A } ø
   B. PIPING AND VALVES BEYOND OUTERMOST REAC. ISOL. VALVES, EXCEPT THOSE LINES DESIG. AS 3/4"RHR(56)-2:
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B } ø
   C. INSTM. AIR LINES & LEAK-OFF PIPING INSIDE CONT. ISOL. VALVES:
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B
   D. INSTR. AIR LINES OUTSIDE CONTAINMENT ISOL. VALVES:
      SEISMIC CATEGORY I
      QUALITY CLASS II
      CODE GROUP D } ø
   E. LEAK-OFF PIPING BEYOND LEAK-OFF ISOL. VALVES & THE LINES DESIGNATED AS 3/4"RHR(56)-2:
      SEISMIC CATEGORY II⊕
      QUALITY CLASS II
      CODE GROUP D
   F. PIPING SUBSYSTEMS: EDR(20)-1 & FDR(43):
      SEISMIC CATEGORY II⊕
      QUALITY CLASS II+
      CODE GROUP D+

   ⊕ HANGERS TO BE DESIGNED TO SEISMIC CATEGORY I LOADS.
   ø EXCEPT AS NOTED ON M619 INSTR. CONN. DIAGRAMS.
   \+ SEE NOTE 12, WNP-2 SPEC., SECT. 15B.1, TABLE 2 NOTES.
4. CODE BREAK DEFINITIONS FOR THERMOWELLS ARE SHOWN ON M610, "INSTALLATION OF THERMOWELLS AND SAMPLE PROBES."
5. DELETED
6. ALL PIPING SYSTEMS IDENTIFIED BY THE PREFIX "PI" SHALL BE SUPPLIED & INSTALLED BY CONTRACT #220.
7. THIS EQUIPMENT IS NORMALLY CONTROLLED FROM THE MAIN CONTROL ROOM. IF THE MAIN CONTROL ROOM MUST BE VACATED, THIS CONTROL POINT MAY BE ISOLATED AND CONTROL TRANSFERRED TO THE REMOTE SHUTDOWN PANEL C61-P001.
8. DELETED
9. ALLOW ADEQUATE PIPING SURFACE AREA FOR COOLING OF PUMP RHR-P-3.
10. ALL TEST CONNECTION PIPING WILL ASSUME "RATING" OF SOURCE PIPE AND BE IDENTIFIED AS 3/4"RHR(55)-" ," UNLESS OTHERWISE NOTED BY SPECIFIC LINE NUMBER.
11. EXCESS FLOW CHECK VALVES SHALL BE TAGGED AS FOLLOWS: PI-EFC-X* (*=PENETRATION NUMBER).
12. CONTAINMENT INSTRUMENTATION ROOT VALVES SHALL BE TAGGED AS FOLLOWS: PI-VX-* (*=PENETRATION) EXCEPT WHERE NOTED ON FACE OF DRAWING.
13. EQUIPMENT AND INSTRUMENTS ARE PREFIXED WITH RHR UNLESS OTHERWISE NOTED.
14. SEE COMPUTER I/O LIST FOR MOTOR WINDING AND BEARING TEMPERATURE ELEMENTS AND POINT NUMBERS.
15. PIPING, VALVES, AND ASSOCIATED COMPONENTS ON THIS DWG. SHALL BE CLASSIFIED AS FOLLOWS (BREAK POINTS ARE INDICATED ON THIS DIAGRAM):
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B

   ⊖ (ASME III/2 WITH EXCEPTIONS. SEE PROCUREMENT SPECIFICATION 12023)
16. THESE INSTRUMENTS ARE LOCATED ON COLD SHUTDOWN PANEL.
17. ALL PIPING DOWNSTREAM OF THE LAST ISOLATION VALVE AND OPEN TO THE ATMOSPHERE WITH THE SUBSYSTEM DESIGNATION "SYSTEM"(50) THRU (59) SHALL BE CLASSIFIED AS CODE GROUP D WITH QUALITY CLASS AND SEISMIC CATEGORY PROVIDED BY THE APPLICABLE NOTES ON THIS DRAWING.
18. ALL INSTRUMENT LINES ARE DESIGNATED BY CODE AND LINE NUMBER.
   A. EXAMPLE: LINES ORIGINATING OUTSIDE CONTAINMENT.
      $\underbrace{\text{1/2"PI(1)-ST}}_{\text{CODE DESIGNATION}}$ – $\underbrace{\text{(H22-P021)-A6}}_{\text{LINE NUMBER}}$
   B. EXAMPLE: LINES ORIGINATING INSIDE CONTAINMENT.
      $\underbrace{\underbrace{\text{1/2"PI(1)-4S}}_{\text{CODE DESIGNATION}}\text{ – X106}}_{\text{LINE NUMBER}}$
   C. EXAMPLE: CONTINUATION OF THE ABOVE LINE OUTSIDE CONTAINMENT IS DESIGNATED AS FOLLOWS (WITH LINE NUMBERS NOT SHOWN).
      $\underbrace{\text{1/2"PI(1)-ST-X106}}_{\text{CODE DESIGNATION}}$ – $\underbrace{\text{(H22-P021)-}}_{\text{LINE NUMBER}}$
19. ALL ITEMS IN CROSSHATCHED AREA ARE PART OF THE RHR STEAM CONDENSING MODE WHICH HAS BEEN DEACTIVATED. THE PIPING, VALVES, AND INSTRUMENTATION AS SHOWN ON THE DIAGRAM ARE INSTALLED. MOTOR OPERATED VALVES THAT HAVE BEEN DE-ENERGIZED AND LOCKED CLOSED ARE RHR-V-52A & B, RHR-V-11A & B, RHR-V-26A & B, RHR-V-87A & B, RHR-V-124A & B, RHR-V-125A & B (REF. PED 215-M-X467). EXCEPTION: CONTROL AND INDICATION FOR RHR-V-26B HAS BEEN REMOVED. REMOVED ALL CONTROL ROOM PANEL WIRING. REMOVED AND SPARED PANEL INSTRUMENTATION. LIFTED AND SPARED ALL FIELD CABLES, AND SPARED IN PLACE ALL PROCESS INSTRUMENTATION.
20. THESE INSTRUMENTS ARE LOCATED ON THE ALTERNATE REMOTE SHUTDOWN PANEL E-CP-ARS
21. THIS EQUIPMENT IS NORMALLY CONTROLLED FROM THE MAIN CONTROL ROOM. IF THE MAIN CONTROL ROOM MUST BE VACATED, THIS CONTROL POINT MAY BE ISOLATED AND CONTROL TRANSFERRED TO THE ALTERNATE REMOTE SHUTDOWN PANEL E-CP-ARS.
22. POWER HAS BEEN REMOVED FROM THIS MOV BY A MAINTAINED OPEN DISCONNECT SWITCH REMOTE FROM THE MAIN CONTROL ROOM WITH THE VALVE MAINTAINED CLOSED. ALL AUTOMATIC INTERLOCKS STILL FUNCTION WHEN THE MOTOR FEEDER POWER SWITCH IS CLOSED. CONTROL OF THIS VALVE IS RE-ESTABLISHED AND A HI/LOW RPV PRESSURE INTERFACE ALARM FOR MAIN CONTROL ROOM OPERATION DURING A DESIGN BASIS FIRE IS PROVIDED FOR OPERATOR INFORMATION.
23. RHR-LPCS CROSSTIE SPOOL PIECE IS NOT INSTALLED.
24. THESE VALVES ARE 1/2" VALVES, BUTT WELDED TO SPECIALLY PREPARED 3/4"ø NIPPLES.
25. 1/4" HOLE DRILLED ON REACTOR SIDE OF RHR-V-8 WEDGE.
26. VALVES RHR-V-47A & B HAVE BEEN DEACTIVATED. THE PIPING AND VALVES AS SHOWN ON THIS DIAGRAM ARE INSTALLED. THE ELECTRICAL POWER, CONTROL ROOM AND REMOTE SHUTDOWN CONTROL SWITCHES, PANEL WIRING, AND FIELD CABLES (EXCEPT AT THE VALVES DUE TO RADIOLOGICAL CONCERNS) HAVE BEEN REMOVED.
27. AIR OPERATOR AND AIR SUPPLY FOR TESTABLE CHECK VALVES RHR-V-41A, 41B, 41C, 50A, 50B & 89 ARE DEACTIVATED AND SPARED IN PLACE, THESE VALVES ARE TESTED PER THE IST PROGRAM. PENETRATION AND ISOLATION/TEST VALVES ARE STILL ACTIVE.
28. ALL ITEMS IN THE CROSSHATCHED AREA ARE PART OF THE HYDROGEN RECOMBINER SYSTEM (CONTAINMENT ATMOSPHERE CONTROL-"CAC") WHICH HAS BEEN DISABLED. PRIMARY CONTAINMENT VALVES RHR-V-134A AND RHR-V-134B HAVE BEEN DE-ENERGIZED AND LOCKED CLOSED. VALVES RHR-V-176A AND RHR-V-176B HAVE BEEN LOCKED CLOSED (REF PDC 3539)
29. FOR PERIODIC THERMAL PERFORMANCE TESTING OF RHR-HX-1A, FOUR THERMISTORS ARE INSTALLED ON THE RHR WATER INLET SIDE OF RHR-HX-1A, EIGHT THERMISTORS ARE INSTALLED ON THE RHR WATER OUTLET SIDE OF RHR-HX-1A AND AN ULTRASONIC FLOW ELEMENT IS ON THE RHR WATER INLET PIPE OF RHR-HX-1A. THESE ARE MOUNTED QCII+, SC IM.
30. FOR PERIODIC THERMAL PERFORMANCE TESTING OF RHR-HX-1B, FOUR THERMISTORS ARE INSTALLED ON THE RHR WATER INLET SIDE OF RHR-HX-1B, EIGHT THERMISTORS ARE INSTALLED ON THE RHR WATER OUTLET SIDE OF RHR-HX-1B AND AN ULTRASONIC FLOW ELEMENT IS ON THE RHR WATER INLET PIPE OF RHR-HX-1B. THESE ARE MOUNTED QCII+, SC IM.
31. RHR-V-60A AND RHR-V-75A HAVE BEEN DEACTIVATED-DISABLED. VALVE INTERNALS HAVE BEEN REMOVED TO ALLOW CONTINUOUS FLOW PER EC 11109.
32. TYGON HOSE (REF DWG D-VENTDRAINHOSE-319) WITH QUICK DISCONNECT IS PROVIDED AS A MEANS TO VISIBLY VERIFY THAT ANY AIR HAS BEEN PROPERLY VENTED FROM THE SYSTEM AND MAY BE LEFT IN PLACE.
33. SEE DWG M501 FOR FLOW DIAGRAM LEGENDS, SYMBOLS AND ABBREVIATIONS.

LEGEND:

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES AND AS NOTED ON DIAGRAM) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE.
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

REFERENCES TO CONTRACT NUMBERS, SUCH AS 215, 206, 220, FOUND IN THE NOTES ON THIS DRAWING REFER TO ORIGINAL CONSTRUCTION DESIGN REQUIREMENTS.

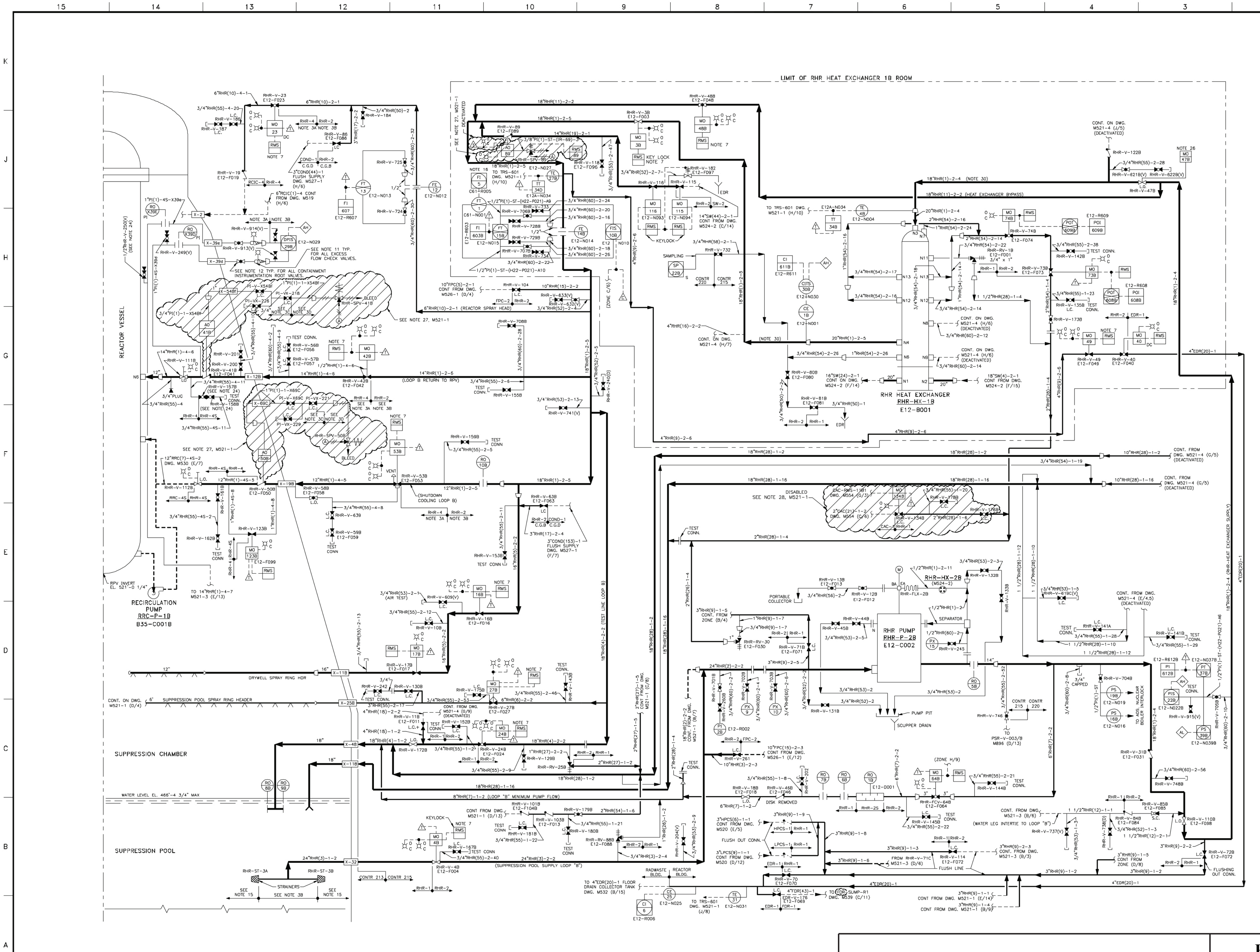
CURRENT DESIGN REQUIREMENTS ARE DOCUMENTED IN THE STATION DESIGN SPECIFICATIONS AND ACTIVE CONTRACT SPECIFICATIONS WHICH STILL APPLY.

FSAR FIG.

Columbia Generating Station
Final Safety Analysis Report

Residual Heat Removal System – P&ID

Draw. No. M521-1 | Rev. 115 | Figure 5.4-15.1



NOTES:

FOR NOTES SEE M521-1.

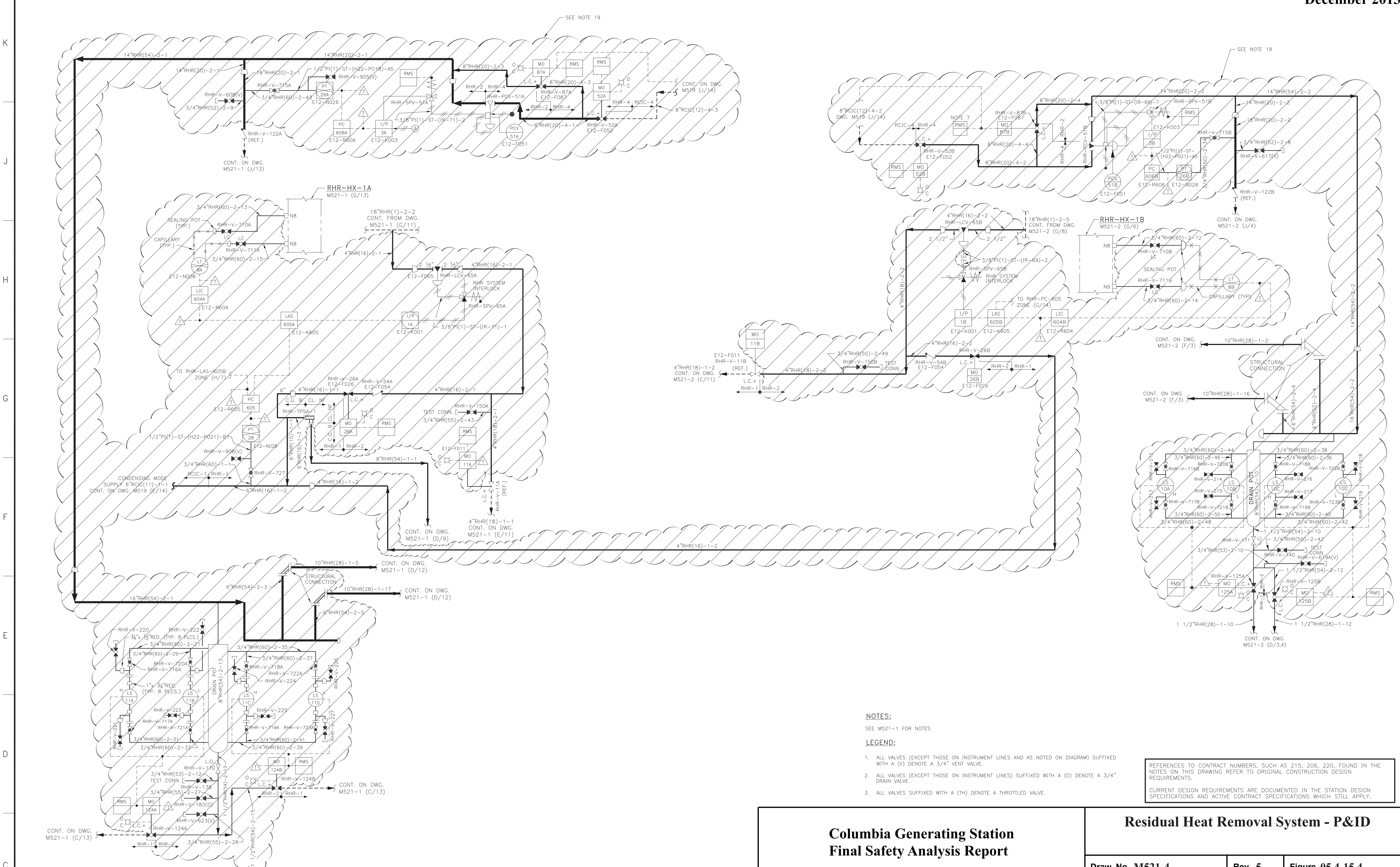
LEGEND:

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE EXCEPT AS NOTED.
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

REFERENCES TO CONTRACT NUMBERS, SUCH AS 215, 206, 220, FOUND IN THE NOTES ON THIS DRAWING REFER TO ORIGINAL CONSTRUCTION DESIGN REQUIREMENTS.

CURRENT DESIGN REQUIREMENTS ARE DOCUMENTED IN THE STATION DESIGN SPECIFICATIONS AND ACTIVE CONTRACT SPECIFICATIONS WHICH STILL APPLY.

Columbia Generating Station Final Safety Analysis Report	Residual Heat Removal System - P&ID		
	Draw. No. M521-2	Rev. 115	Figure 5.4-15.2



NOTES:

SEE M521-1 FOR NOTES

LEGEND:

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES AND AS NOTED ON DIAGRAM) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE.
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

REFERENCES TO CONTRACT NUMBERS, SUCH AS 215, 206, 220, FOUND IN THE NOTES ON THIS DRAWING REFER TO ORIGINAL CONSTRUCTION DESIGN REQUIREMENTS.

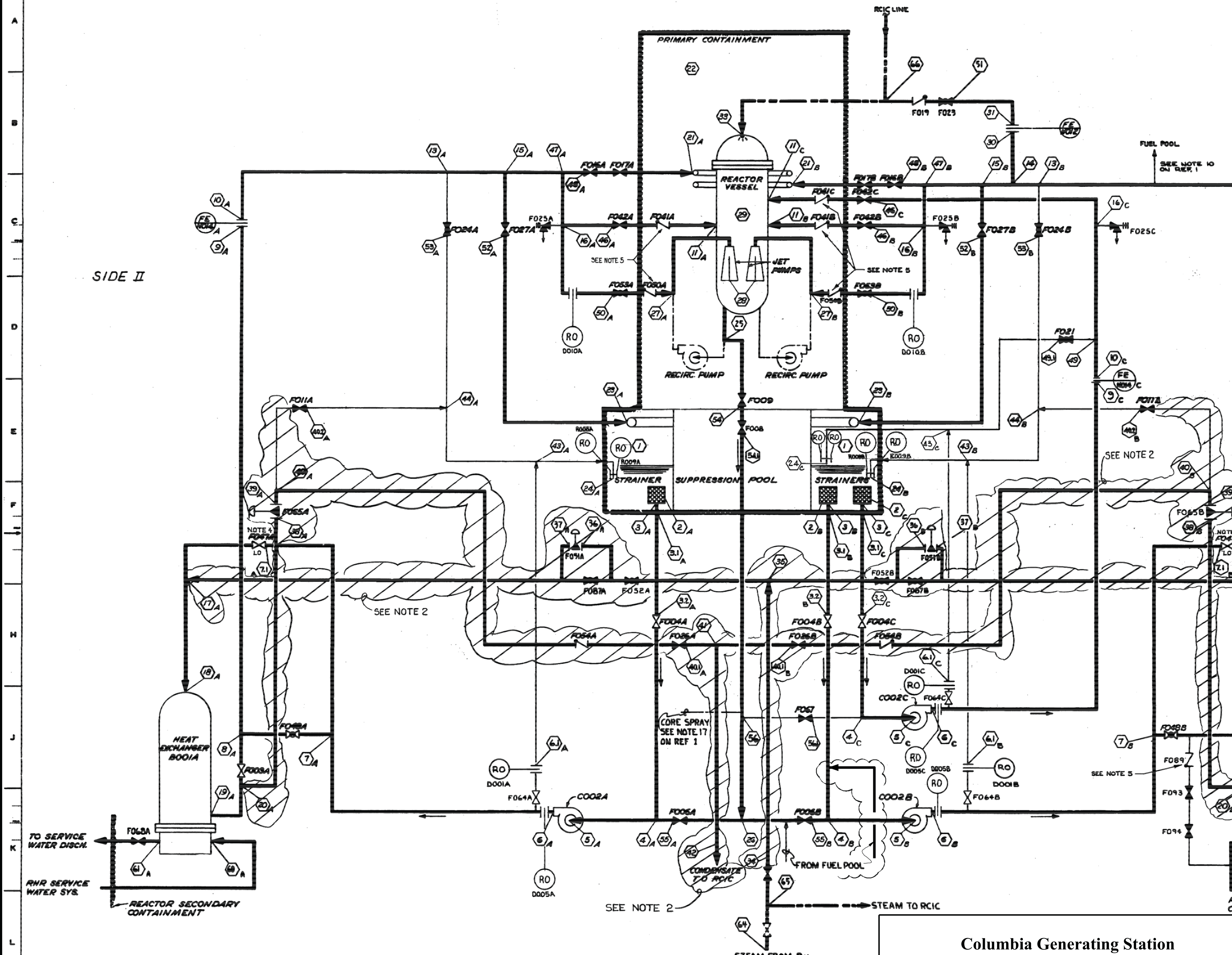
CURRENT DESIGN REQUIREMENTS ARE DOCUMENTED IN THE STATION DESIGN SPECIFICATIONS AND ACTIVE CONTRACT SPECIFICATIONS WHICH STILL APPLY.

Columbia Generating Station Final Safety Analysis Report	Residual Heat Removal System - P&ID
	Draw. No. M521-4	Rev. 5	Figure 05.4-15.4

FCF 298X184 G1,2,3,4,8&10 (E12-1020)

NOTES:

1. FOR DATA PERTAINING TO NUMBERS WITHIN HEXAGONS REFER TO PROCESS DATA REF 1.
2. RHR STEAM CONDENSING MODE HAS BEEN DEACTIVATED.
3. NOT USED.
4. VALVES RHR-V-47A & RHR-V-47B HAVE BEEN DEACTIVATED. THE ELECTRICAL POWER, CONTROL ROOM AND REMOTE SHUTDOWN CONTROL SWITCHES, PANEL WIRING, AND FIELD CABLES (EXCEPT AT THE VALVES DUE TO RADIOLOGICAL CONCERNS) HAVE BEEN REMOVED.
5. THE TESTABLE FUNCTION FOR THIS VALVE HAS BEEN DEACTIVATED AND SPARED IN PLACE.
6. FOR ADDITIONAL DETAIL ON RHR AND SW SYSTEMS, SEE FLOW DIAGRAMS, M521 SHTS 1-4 AND M524 SHTS 1-3 RESPECTIVELY.



REFERENCE DOCUMENTS:	MPL ITEM NO.
1. RESIDUAL HEAT REMOVAL PROCESS DATA	E12-1020
2. RESIDUAL HEAT REMOVAL SYSTEM P&ID	E12-1010
3. NUCLEAR BOILER PROCESS DATA	B21-1020/ B22-1020

Columbia Generating Station
Final Safety Analysis Report

Residual Heat Removal System Process Diagram

Draw. No. 02E12-04,1,1 | Rev. 10 | Figure 5.4-16

(SEE NOTE 3) MODE F

POSITION ○	1	2	3	4	5	6	49	7	8	9	10	13	23/24	1
FLOW-GPM	—	7450	←									→	7450	—
PRESS-PSIA	14.7	X	X	X	X	X	X	X	X	X	X			14.7
TEMP °F		120/40	←									→	120/40	—
MAX. PRESS. DROP-FEET	←				•TDH=267•									→

Rx PRESS. 135 PSIG MODE G

POSITION ○	29	25	26	4	5	6	43	24	1			1	2 BC	3 BC	4 BC	5 BC	6 BC	6.2	43 B	24 B	1
FLOW-GPM	—	550	←				→	550	—			—	550	←					→	550	—
PRESS-PSIA	150	X	X	X	X			X	14.7			14.7	X	X	X	X				X	14.7
TEMP °F	—	358	←				→	358	—			—	125/40	←					→	125/40	—
MAX. PRESS. DROP-FEET	←				TDH=650 SEE NOTE 22				→			←				TDH=650 SEE NOTE 22					→

MODE S

POSITION ○	1	2 A,B,C	3 A,B,C	4 A,B,C	5 A,B,C	6 A,B,C	18 A,B	19 A,B	20 A,B	9 A,B,C	10 A,B,C	46 A,B,C	11 A,B,C	48 A,B	21 A,B	50 A,B	27 A,B	51	33	52 A,B	53 A,B
FLOW-GPM	N/A	←																		→	N/A
PRESS.-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	1015	X	15.5	X	1015	X	1015	X	X
TEMP °F	90/40	←									→	90/40	547	90/40	135	90/40	547	90/40	547	90/40	90/40
MAX. PRESS DROP-FEET					O																

MODE S (CONT'D)

POSITION ○	54	56	55 A,B		34	35	36 A,B	37 A,B	17 A,B		20 A,B	38 A,B	40 A,B	41	42
FLOW-GPM	N/A	N/A	N/A		N/A	←		→	N/A		N/A	←		→	N/A
PRESS.-PSIA	X	X	X		X	X	X	X	X		X	X	X	X	X
TEMP °F	AMB	AMB	AMB		AMB	AMB	AMB	90/40	90/40		90/40	90/40	AMB	AMB	AMB
MAX PRESS DROP-FEET															

(SEE NOTE 24) MODE C-3 4 HRS 135PSIG R_X PRESS

POSITION ○	29	64	65	34	35	36 A,B	37 A,B	17 A,B	18 A,B	19 A,B	20 A,B	38 A,B	39 A,B	40 A,B	41	42					60 A,B	61 A,B		
FLOW SEE NOTE 15	—	119.6	114.4	←→	114.4	57.2	←	→	57.2	116	←		→	116	232	232					7400	7400		
PRESS.-PSIA	150					X	X	X	>60	X	X	X	X	X		59.7/14.7					X	X		
TEMP °F	—	323	←					→	323	140	←				→	140					95	111.8		
MAX PRESS DROP-PSI	←						ΔP=90.3/135.3									→								

HEAT REMOVAL PER STEAM CONDENSING HX 62.15 X 106 BTU/HR (2 HX STEAM CONDENSING)

(SEE NOTE 24) MODE C-4 8 HRS 135PSIG R_X PRESS

POSITION ○	29	64	65	34	35	36 A	37 A	17 A	18 A	19 A	20 A	38 A	39 A	40 A	41	42					60 A	61 A		
FLOW SEE NOTE 15		98.7	93.5	←				→	93.5	190	←				→	190					7400	7400		
PRESS PSIA	150	X	X	X	X				>60	X					X	59.7/14.7					X	X		
TEMP °F	—	323	←					→	323	140	←				→	140					95	122.5		
MAX PRESS DROP-PSI	←						ΔP=90.3/135.3									→								

HEAT REMOVAL PER STEAM CONDENSING HX 101.6 X 10^6 BTU/HR (1 HX STEAM CONDENSING)

(SEE NOTE 3 & 14) MODE A-1

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	7450	←								→	7450	--
PRESS.-PSIA	59.7/14.7	X	X	X	X								85.7/40.7
TEMP °F	—	170/40	←								→	170/40	
MAX. PRESS. DROP-FEET	←				•TDH=267•				•ΔH= 17•			•ΔH=40•	→

SEE NOTE 27

(SEE NOTE 14) MODE A-2

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	8000	←								→	8000	—
PRESS.-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	14.7
TEMP °F	—	180/90	←								→	180/90	—
MAX. PRESS. DROP-FEET	←				•TDH=235•								→

MODE B

POSITION ○	1	2 A,B	3 A,B	4 A,B	5 A,B	6 A,B	7 A,B	17 A,B	18 A,B	19 A,B	20 A,B	8 A,B	9 A,B	10 A,B	13 A,B	14	15 A,B	21 A,B	22	23 A,B	1		60 A,B	61 A,B
FLOW-GPM	—	7900	←													→	7900	7450	—	450	—		7400	7400
PRESS-PSIA	59.7/14.7					X	X	X	X	X	X	X	X	X	X	X			59.7/14.7		59.7/14.7		X	X
TEMP °F	—	212	←					→	212	179.3	179.3	179.3	179.3	179.3	179.3	179.3	179.3	179.3	—	179.3	—		95	128.8
MAX. PRESS. DROP-FEET	←				•TDH=235•														→		→			

HEAT REMOVAL PER HX 121.7X10^6 BTU/HR (1 HX OPERATING) SEE NOTE 16

INDICATES FLOW PASSING THRU ABOVE POSITIONS (TYP)

SEE NOTE 7 (TYP)

(SEE NOTE 24) MODE C-1 R_X PRESS 1000 PSIG

POSITION ○	29	34	35	36 A,B	37 A,B	17 A,B	18 A,B	19 A,B	20 A,B	38 A,B	39 A,B	40 A,B	41	42	40.2 A,B	24 A,B	1		60 A,B	61 A,B
FLOW- SEE NOTE 15	—	187.1	187.1	93.5	←	→	93.5	190	←		→	190	380	380	190	190	—		7400	7400
PRESS-PSIA	1015	X	X	X	214.7	X	X	X	X	X	X	X		59.7			14.7		X	X
TEMP °F	—	546	546	546	387.7	387.7	387.7	140	←						→	140	—		95	122.4
MAX. PRESS. DROP-PSI	←	ΔP=800			→	←			ΔP=200 / ΔP=155					→		→				

HEAT REMOVAL PER HX 101.4 X10^6 BTU/HR (2 HX STEAM CONDENSING)

(SEE NOTE 24) MODE C-2 R_X PRESS 1000 PSIG

POSITION ○	29	34	35	36 A	37 A	17 A	18 A	19 A	20 A	38 A	39 A	40 A	41	42		60 A	61 A
FLOW SEE NOTE 15	—	136.2	←			→	136.2	277	←				→	277		7400	7400
PRESS-PSIA	1015	X	X	X	214.7	X	X	X					X	59.7		X	X
TEMP °F	—	546	546	546	387.7	387.7	387.7	140	←				→	140		95	134.8
MAX PRESS DROP-PSI	←		ΔP=800		→	←				ΔP=155				→			

DUTY PER STEAM CONDENSING HX 147.5 X10^6 BTU/HR (1 HX STEAM CONDENSING)

(SEE NOTE 24) MODE C-2 (CONT'D) (SEE NOTE 14)

POSITION ○	1	2 A,B	3 A,B	4 A,B	5 A,B	6 A,B	7 A,B	17 A,B	18 A,B	19 A,B	20 A,B	9 A,B	10 A,B	13 A,B	43 A,B	24 A,B	1		60 A,B	61 A,B
FLOW/GPM	—	7450	←												→	7450	—		7400	7400
PRESS.-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	14.7		X	X
TEMP °F	—	120/70	←					→	120/70	103.1	103.1	103.1	103.1	103.1	103.1	103.1	—		95	103.2
MAX. PRESS. DROP-FEET	←				•TDH=267•												→			

HEAT REMOVAL PER POOL COOLING HX 26.0 X 10^6 BTU/HR (1 HX OPERATING)

MODE D (SEE NOTE 26) RX PRESS 48 PSIG

POSITION ○	29	25	26	4 A,B	5 A,B	6 A,B	18 A,B	19 A,B	8 A,B	9 A,B	10 A,B	14	27 A,B	28	30	31	51	33	29				60 A,B	61 A,B
FLOW/GPM	—	7450	7450	7450	7450	7450	←7450	←7450	7450	←	→	7450	7450/6580	7450/6580	870/0	870/0	870/0	870/0	—				7400	7400
PRESS-PSIA	62.7			X	X	X	X	X	X	X	X	X	X	X	62.7				110				X	X
TEMP °F	—	295	←			→	295	295	295	295	295	295	295	295	295	295	295	295	—				85	125
MAX PRESS DROP-FEET	←				•TDH=267•										•ΔH=	17•		•ΔH=	→					

HEAT REMOVAL PER HX 148X10^6 BTU/HR (1 HX OPERATING) SEE NOTE 21

SEE RCIC (REF 3)

MODE E RX PRESS 0 PSIG

POSITION ○	29	25	26	55 A,B	4 A,B	5 A,B	6 A,B	18 A,B	19 A,B	9 A,B	10 A,B	11 A,B	16 A,B	27 A,B	28 A,B	29		60 A,B	61 A,B
FLOW-GPM	—	14,900/7450	14,900	7450	←									→	7450	—		7400	7400
PRESS.-PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X				14.7		X	X
TEMP °F	—	125/AMB	←				→	125/AMB	113.8	113.8	113.8	113.8	113.8	113.8	113.8	—		85	96.3
MAX PRESS DROP-FEET	←					•TDH=267•		•ΔH=23.3•							•ΔH=18• →			•ΔH=23.1•	

LOOPS A & B ONLY

DUTY PER HX 41.6X10^6 BTU/HR (2 HX'S OPERATING)

MODES:

A-1 ACCIDENT WITH RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMP OPERATION. SEE NOTE 25

A-2 ACCIDENT WITH RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMP OPERATION. SEE NOTE 25 (10 MIN)

B POST ACCIDENT CONTAINMENT SPRAY WITH HEAT REJECTION WITH ONE PUMP OPERATION. SEE NOTE 25 (PEAK SUPPRESSION POOL TEMPERATURE)

C-1 REACTOR ISOLATION - 2HX STEAM CONDENSING (1/2 HR) SEE NOTE 24

C-2 REACTOR ISOLATION - 1HX STEAM CONDENSING AND 1HX POOL COOLING (1 1/2 HR) SEE NOTE 24

C-3 REACTOR ISOLATION - 2HX STEAM CONDENSING (4 HR) SEE NOTE 24

C-4 REACTOR ISOLATION - 1HX STEAM CONDENSING (8 HR) SEE NOTE 24

D NORMAL SHUTDOWN AFTER BLOWDOWN TO MAIN CONDENSER

E CONTINUATION OF NORMAL SHUTDOWN FROM PLANT MODE "D" (AT 0 PSIG) AND FUNCTIONAL PUMP TEST AFTER SHUTDOWN.

F RHR SYSTEM TEST DURING PLANT OPERATION.

G MINIMUM FLOW BYPASS MODE.

S SYSTEM ON STANDBY DUTY

LEGEND

R_X PRESS----REACTOR VESSEL PRESSURE
TDH----TOTAL DYNAMIC HEAD
SOH----SHUTOFF HEAD
ΔH----HEAD LOSS
ΔP----PRESSURE LOSS

REFERENCE DOCUMENTS:	MPL ITEM NO.
1. RESIDUAL HEAT REMOVAL SYSTEM P&ID	E12-1010
2. RESIDUAL HEAT REMOVAL SYSTEM DESIGN SPEC	E12-4010
3. RCIC PROCESS DIAGRAM	E51-1070
4. RECIRC SYSTEM PROCESS FLOW DIAGRAM	B35-1040
5. LOW PRESSURE CORE SPRAY PFD	E21-1020

NOTES

1. PROCESS DIAGRAM 731E966 SHALL BE USED WITH AND FORM A PART OF THIS PROCESS DATA. IF THERE ARE ANY CONFLICTS BETWEEN THE PROCESS DIAGRAM AND THIS PROCESS DATA, THE PROCESS DATA SHALL GOVERN.
2. PIPING BETWEEN POINTS WITH EMPTY DATA BLANKS (SEE ALSO TABLE 3) SHALL BE SIZED BY OTHERS BASED ON SPECIFIED OPERATING CONDITIONS. EMPTY DATA BLANKS CAN BE FILLED IN BASED ON ACTUAL ARRANGEMENT BY OTHERS. X = INDICATES THE DATA IS NOT SIGNIFICANT.
3. SHOWN AS TYPICAL FOR ONE LOOP. IF LOOPS ON SIDE I AND SIDE II ARE NOT SYMMETRICALLY ARRANGED, VALUES FOR BOTH SIDES SHALL BE SUBMITTED.
4. ΔP VALUES FOR EQUIPMENT WITHIN GE-BWRSD SCOPE ARE AS NOTED.
5. ELEVATIONS ARE NOT INCLUDED IN ΔP, VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
6. X/Y = INDICATES MAXIMUM (X) AND MINIMUM (Y) VALUES FOR THE MODE SPECIFIED.
7. DASHED LINES INDICATE FLOW DOES NOT PASS THRU THESE POINTS.
8. THE NPSH AVAILABLE IN MODES B & D AT THE CENTERLINE OF THE SUCTION NOZZLE ARE DEFINED IN CALCULATION 5.17.19
9. SERVICE WATER CROSSTIE, SHALL BE SIZED TO FLOW 300 GPM.
10. THIS PORTION OF PIPING TO BE SIZED BASED ON FLOW SHOWN ON THE FUEL POOL PROCESS DIAGRAM.
11. TABLE 1 INDICATES TYPICAL VALVE POSITIONS DURING VARIOUS MODES OPERATED.
12.
13.
14. TYPICAL VALUES FOR MAX. AND MIN. SUPPRESSION POOL TEMP SHOWN. FINAL TEMPERATURES DEPEND ON INITIAL POOL WATER TEMPERATURE & POOL WATER VOLUME.
15. WATER FLOWS ARE IN GPM, STEAM FLOWS ARE IN 1000 LBS/HR.
16. H_X DUTY BASED UPON 7450 GPM SHELL SIDE FLOW.
17. FOR LINE SIZING INFORMATION SEE REF. 5.
18. THE WEIGHT OF WATER IN THE SHUTDOWN COOLING SUBSYSTEM PIPING, INCLUDING THE HEAT EXCHANGERS AND PUMPS SHALL NOT EXCEED 225,000LBS AT 70°F TO PREVENT DILUTION OF STANDBY LIQUID CONTROL NEUTRON ABSORBER BELOW MINIMUM REQUIREMENTS.
19.
20. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN PRESSURE & TEMPERATURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENTS.
21. HEAT EXCHANGER CAPABILITY SHOWN AT SERVICE WATER OUTLET TEMP. OF 125°F.
22. PUMP SHUTOFF HEAD 800 FT. MAX.
23. THE HX STEAM INLET PRESSURE SHALL BE GREATER THAN 60 PSIA TO MINIMIZE THE POSSIBILITY OF FLOW INDUCED VIBRATION.
24. THE STEAM CONDENSING MODE HAS BEEN DEACTIVATED.
25. STRAINER PLUGGING CRITERIA ARE DEPICTED IN CALCULATIONS 5.17.19 AND ME-02-97-03
26. DURING REFUELING OUTAGES, THE HEAD SPRAY LINE (NODES 30, 31 & 51) MAY ALSO BE USED TO PROVIDE 1000 GPM FLOW TO THE REACTOR CAVITY FOR DECAY HEAT REMOVAL.
27. MAX FLOW (RUNOUT) FOR RHR-P-2B IS 8100 GPM.

Columbia Generating Station Final Safety Analysis Report	Residual Heat Removal System Process Data
	Draw. No. 02E12-04,22,1 | Rev. 8 | Figure 5.4-17.1

Form No. 960690ai

SEE NOTE 20

POSITION ○	3.1	3.2	4	5	6	7	C	9	10	47	16	46	11	7	7.1	18	19	20	8	3.2C	4C	5C	6	9	10	46	11	23	54.1	26	4AA	5AA	16	50	27
DESIGN PRESS. IN PSIG	125		220	RHR PUMP				500					1250		500	RHR Hx		500			220	RHR PUMP			500		1250	SEE REF 4 PSI/2		220			500		SEE REF 4 PSI-16
DESIGN TEMP IN °F	212		358					480			480		575		358			358			358				480		575			358			480		
ESTIMATED LINE SIZE		24"						18"				12"			18"			18"			24"				18"		12"		20"	18"		24"		12"	
	LPCI LINE (VIA RHR Hx BYPASS)													Hx LINE						LPCI LINE (DIRECT TO REACTOR)								SHUTDOWN SUCTION					SHUTDOWN RETURN LINE		

POSITION ○	34	35	36	37	17	18	15	20	58	39	40	40.1	41	42	14	30	51	51	66	40	40.2	44	47	48	21	15	52	25	15	55	44	45	24
DESIGN PRESS. IN PSIG		1250			500			500			500		125			500		SEE REF. 3		500		125		500			500		500			125	
DESIGN TEMP IN °F		575			480		480			358			212				358			358		500		358	212	358		212	358			300	
ESTIMATED LINE SIZE	10"		8		18		18"				4"						6"				4"			16"			4"				18"		
	STEAM TO HX						CONDENSATE FROM HX								HEAD SPRAY LINE					CONDENSATE TO POOL			DRYWELL SPRAY			SUPPRESSION POOL SPRAY			SYSTEM TEST LINES (LOOPS A & B)				

POSITION ○	56	56.1	4	49	49.1	24	6	6.1		45	6	6.1	49
DESIGN PRESS. IN PSIG	220		125	500		125	500		125		500		125
DESIGN TEMP IN °F	358		212		358		358		300		358		212
ESTIMATED LINE SIZE		18"			18"			4"		4"		4"	
	SYSTEM TEST LINES (LOOP C)						MIN FLOW BYPASS LINES (LOOP C)				MIN FLOW BYPASS([illegible]		

TABLE 1 - VALVE POSITION CHART

SEE NOTE 11

MODE																																	STRAINER AB	STRAINER C
MODE A-1	O	O						O		O	O																						1-30% P	
MODE A-2	O	O						O		O	O																						1-30% P	
MODE B		O					O		O							O	O	O													O		[illegible]	---
MODE C-1				O	T																			T		O	O				O		—	—
MODE C-1				O	T																			T		O	O				O		—	—
MODE C-2				O	T																			T		O	O				O		—	—
C-2 CONT'D		O					O		O										O-T												O		CLEAN	—
MODE C-3				O	O	O																		T		O	O				O		—	—
MODE C-4				O	O	O																		T		O	O				O		—	—
MODE D			O				O	O-T	T					O	O					T		O							O	O	O			
MODE E			O				O		T					O	O													O	O	O	O			
MODE F	O	O					O	O	O									O-T	O-T				O-T										CLEAN	CLEAN
MODE G	O	O	O																									O	O	O		O	CLEAN	CLEAN
MODE S	O	O					O	O	O																								CLEAN	CLEAN

O - VALVE OPEN
T - VALVE THROTTLED
P - STRAINER PLUGGED
T-C - VALVE THROTTLED OR CLOSED
O-T - VALVE OPEN OR THROTTLED
BLANK SPACE INDICATES VALVE IS CLOSED

TABLE 3 LIMITING LINE LOSSES

MODE A-1	6-41 PUMP DISCHARGE LINE TO RPV FLOODING PENETRATION
MODE A-2	NONE
MODE B	1-2-3 (SUCTION LINE SUPPRESSION POOL TO PUMP), 47-21 & 15-25 (CONTAINMENT SPRAY LINES PUMP DISCHARGE TO TO SPRAY HEADERS)
MODE C-1	40-44 (Hx CONDENSATE TO SUPPRESSION POOL), 41-42 (Hx CONDENSATE LINE TO RCIC LINE)
MODE C-2	20-40-41 (Hx CONDENSATE TO RCIC LINE POINT 41)
C-2 CONT'D	NONE
MODE C-3	29-34-35 (STEAM LINE FROM RCIC LINE TO Hx HEADER)
MODE C-4	35-17 (STEAM LINE HEADER TO Hx)
MODE D	14-51-57-29 (VESSEL HEADER SPRAY LINE) 29-25-5 (SHUTDOWN SUCTION LINE RPV TO PUMP) 56-4 (SHUTDOWN SUCTION LINE TEST BRANCH TO PUMP)
MODE E	16-27 (SHUTDOWN DISCHARGE LINE LPCI BRANCH TO RECIRC LOOP)
MODE F	13-43-24-11 49-45 (TEST LINE TO SUPPRESSION POOL)
MODE G	6-43 (PUMP MINIMUM BYPASS LINE)

RHR SYSTEM RELIEF VALVE SET PRESSURES

RELIEF VALVE EPN	GE MPL NUMBER	LINE DESIGN PRESSURE	RELIEF VALVE SET PRESSURE	POSITION DESIGNATION
RHR-RV-25A	E12-F025A	500 PSIG	487 PSIG	16A
RHR-RV-25B	E12-F025B	500 PSIG	488 PSIG	16B
RHR-RV-25C	E12-F025C	500 PSIG	493 PSIG	16C
RHR-RV-30	E12-F030	125 PSIG	103 PSIG	
RHR-RV-88A	E12-F088A	220 PSIG	205 PSIG	4
RHR-RV-88B	E12-F088B	220 PSIG	209 PSIG	4
RHR-RV-88C	E12-F088C	220 PSIG	110 PSIG	4

Columbia Generating Station
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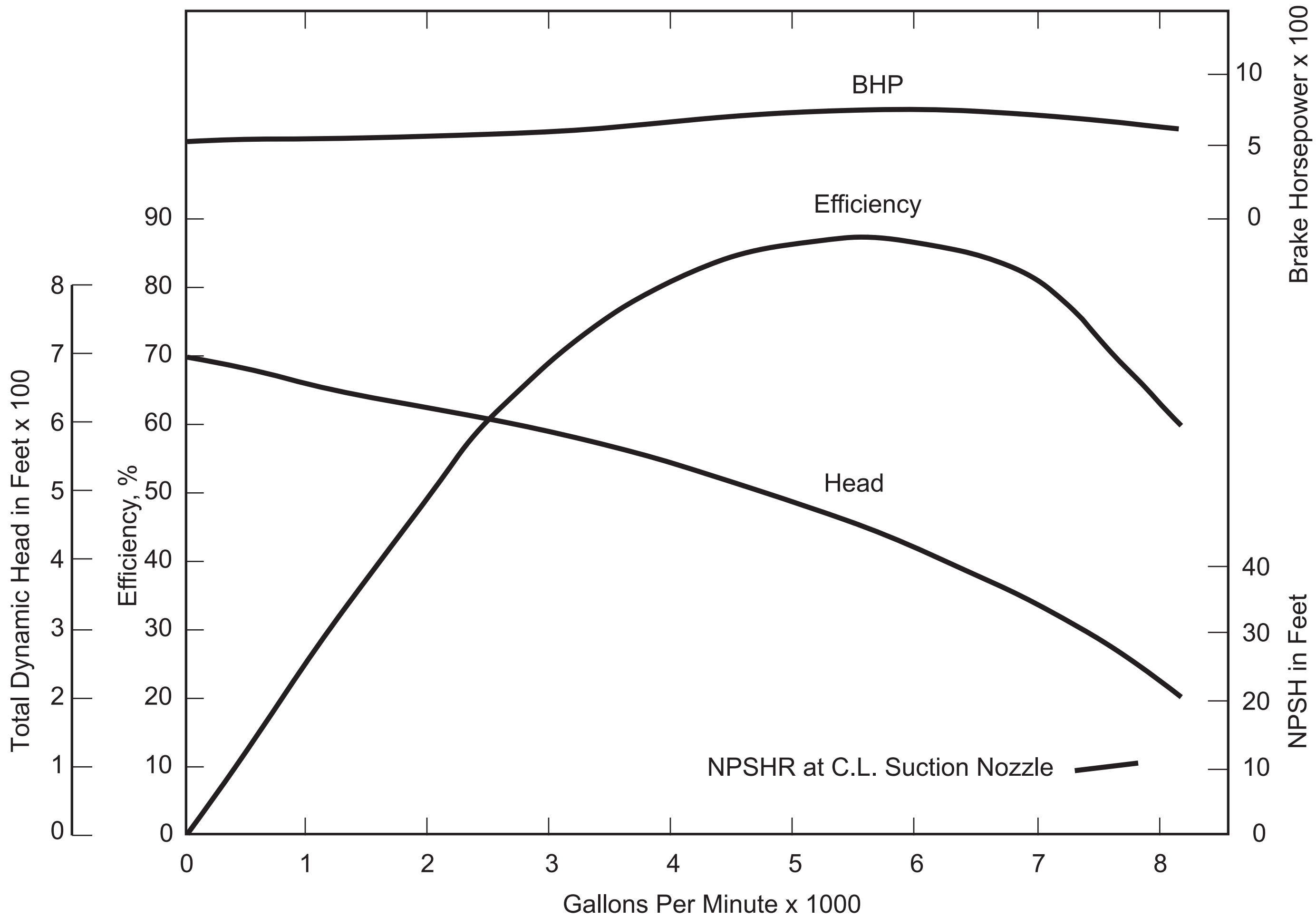
Residual Heat Removal System Process Data

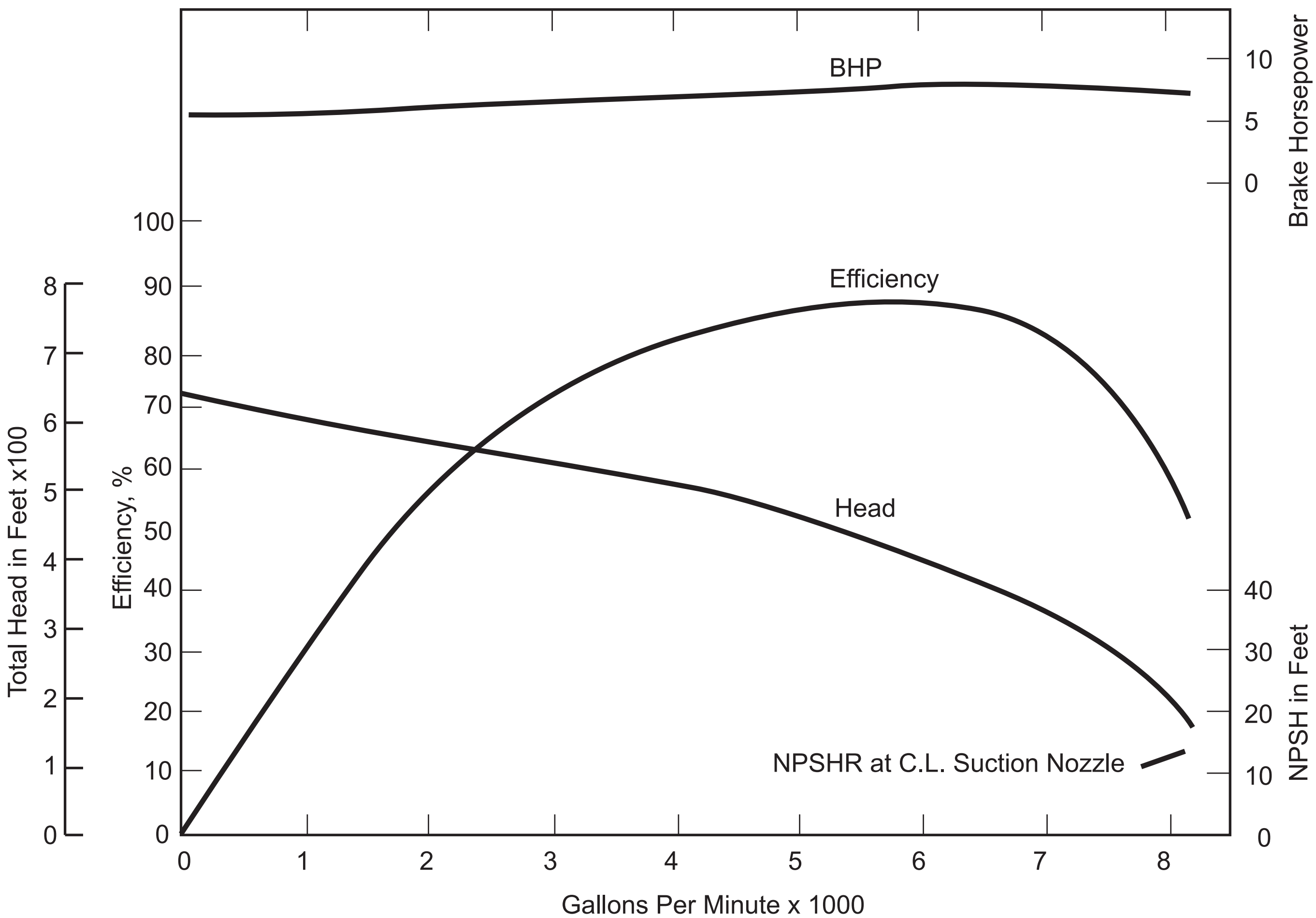
Draw. No. 02E12-04,22,2 | Rev. 6 | Figure 5.4-17.2

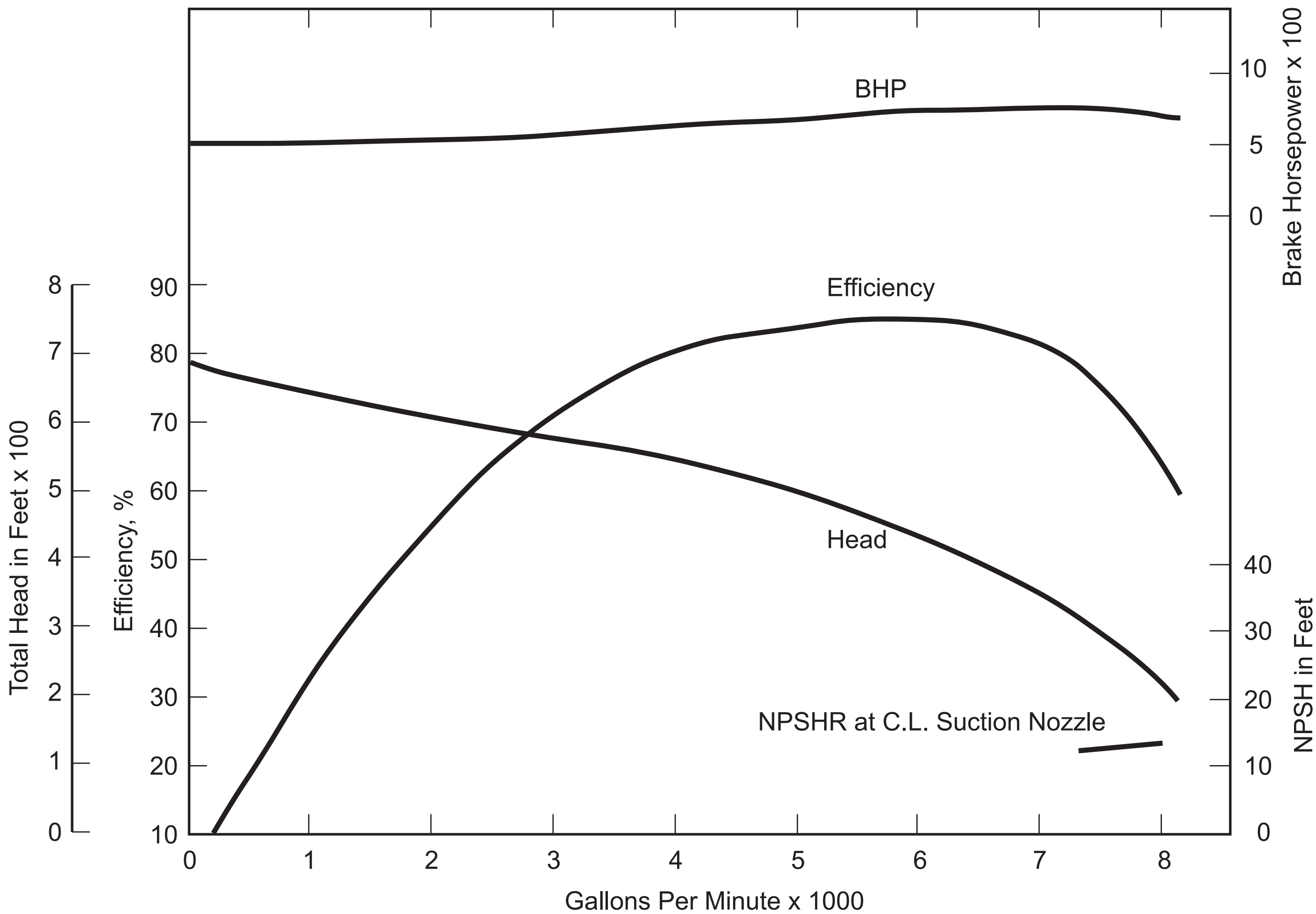


Columbia Generating Station
Final Safety Analysis Report

RHR (LPCI) Pump Characteristics
(S/N 0473113) P-2A

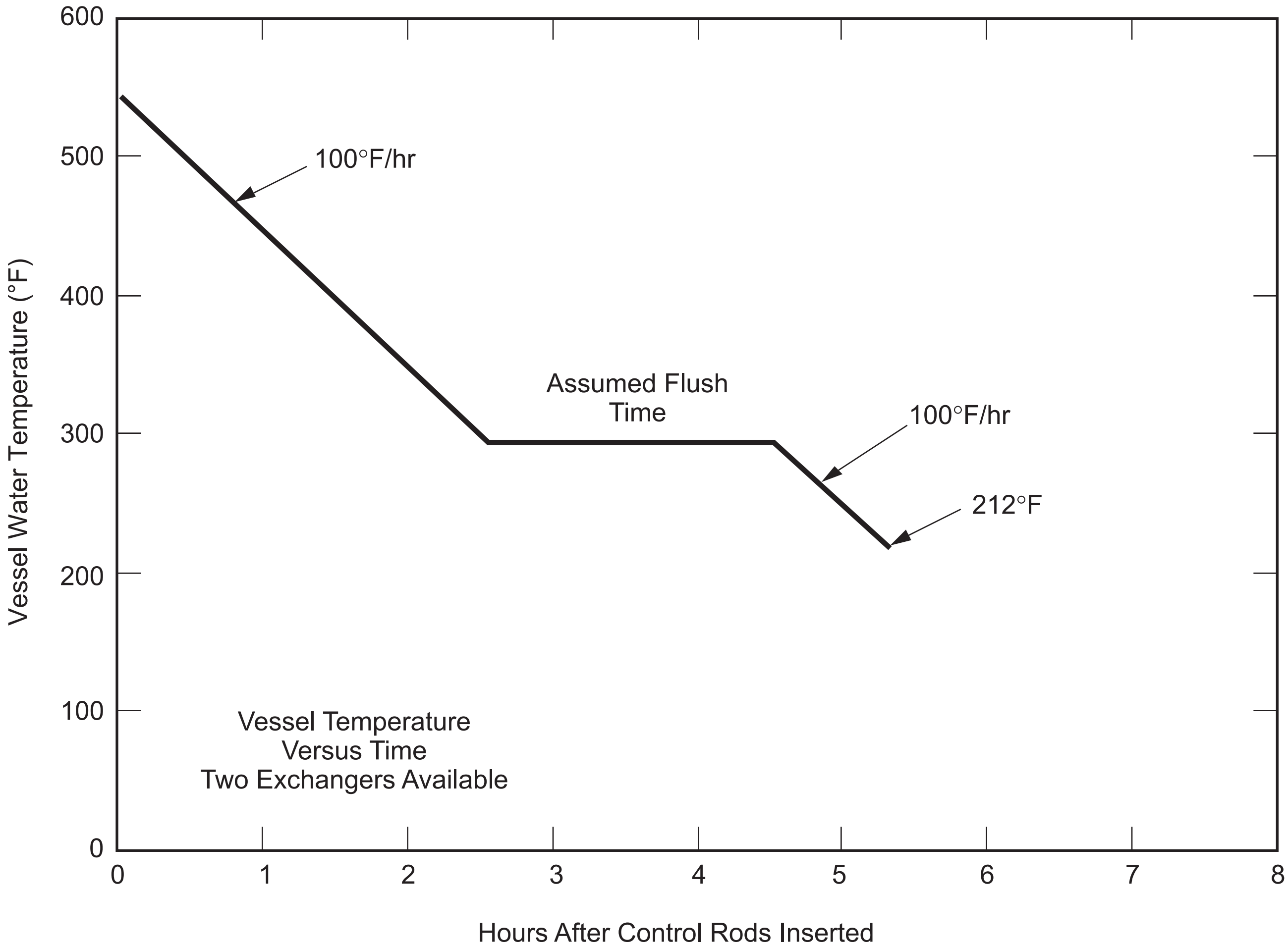
Draw. No. 960690.89	Rev.	Figure 5.4-18


BHP
Efficiency
Head
NPSHR at C.L. Suction Nozzle
Brake Horsepower
0
5
10
NPSH in Feet
0
10
20
30
40
Total Head in Feet x100
0
1
2
3
4
5
6
7
8
Efficiency, %
0
10
20
30
40
50
60
70
80
90
100
0
1
2
3
4
5
6
7
8
Gallons Per Minute x 1000

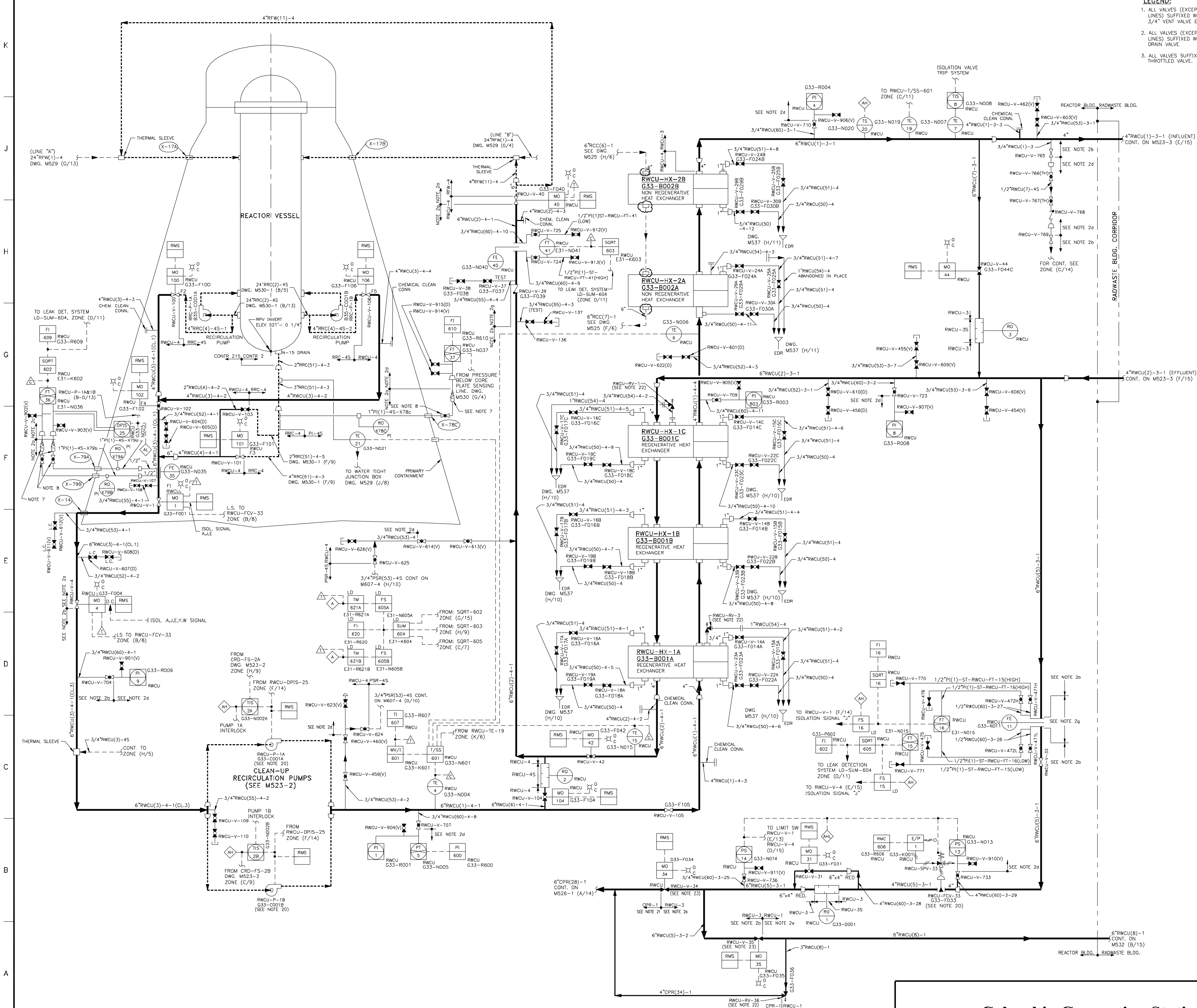


RHR (LPCI) Pump Characteristics
(S/N 0473112) P-2C

Draw. No. 960690.91 | Rev. | Figure 5.4-20



Columbia Generating Station **Final Safety Analysis Report**	**Vessel Coolant Temperature Versus Time** **(Two Heat Exchangers Available)**		
	Draw. No. **960690.88**	Rev.	Figure **5.4-21**



LEGEND:

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE EXCEPT AS NOTED.
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

NOTES:

1. ALL ITEMS MARKED * ARE FURNISHED WITH ASSOCIATED EQUIPMENT.
2. PIPING, VALVES, AND ASSOCIATED COMPONENTS ON THIS DRAWING SHALL BE CLASSIFIED AS FOLLOWS, EXCEPT AS STATED IN NOTE 10: (BREAK POINTS INDICATED ON FLOW DIAGRAM).
   a. PIPING AND VALVES OUT THROUGH THE OUTERMOST ISOLATION VALVES, EXCEPT INSTRUMENT PIPING AS NOTED:
      SEISMIC CATEGORY: I
      QUALITY CLASS: I
      CODE GROUP: A
   b. PIPING AND VALVES BEYOND OUTERMOST ISOLATION VALVES IN REACTOR BUILDING, RADWASTE BUILDING AND RADWASTE CORRIDOR:
      SEISMIC CATEGORY: II ⊕
      QUALITY CLASS: II
      CODE GROUP: C
      } ø
   c. INSTRUMENT LINES AND LEAK OFF PIPING AS NOTED:
      SEISMIC CATEGORY: I
      QUALITY CLASS: I
      CODE GROUP: B
      } ø
   d. INSTRUMENT LINES AND LEAK OFF PIPING AS NOTED:

	REACTOR BLDG	OTHER BLDG
SEISMIC CATEGORY:	II ⊕	II
QUALITY CLASS:	II	II
CODE GROUP:	D	D
	} ø	} ø

   e. PIPING AND VALVES IN RADWASTE BUILDING EXCEPT AS NOTED IN 2b AND 2f.
      SEISMIC CATEGORY: II
      QUALITY CLASS: II +
      CODE GROUP: D +
   f. ALL PIPING, VALVES AND ASSOCIATED EQUIPMENT IN THE CF, COND, CPR, MWR AND SA SYSTEMS IN RADWASTE BUILDING:
      SEISMIC CATEGORY: II
      QUALITY CLASS: II
      CODE GROUP: D
   g. PIPING, VALVES, AND ASSOCIATED COMPONENTS REFERRING TO THIS NOTE:
      SEISMIC CATEGORY: I
      QUALITY CLASS: I
      CODE GROUP: C
      } ø

   ⊕ HANGERS TO BE DESIGNED TO SEISMIC CATEGORY I IN SEISMIC AREA, SUCH AS THE REACTOR BUILDING AND THE RADWASTE BUILDING CORRIDOR.

   ø EXCEPT AS NOTED ON M619 INSTRUMENT CONNECTION DIAGRAMS.

   +SEE NOTE 12, CONTRACT 215, SECTION 15B, TABLE 2 NOTES.

3. ALL PIPING SYSTEMS IDENTIFIED BY THIS PREFIX "PI" SHALL BE SUPPLIED AND INSTALLED BY CONTRACT 220.
4. DELETED
5. ALL INSTRUMENT ROOT VALVES NOT LABELED WILL BE 3/4" GLOBE VALVES UNLESS SPECIFICALLY NOTED OTHERWISE.
6. (DELETED)
7. EXCESS FLOW CHECK VALVES SHALL BE TAGGED AS FOLLOWS: PI-EFC-X (PENETRATION NO.)
8. CONTAINMENT INSTRUMENTATION ROOT VALVES SHALL BE TAGGED AS FOLLOWS: PI-V-X (PENETRATION).
9. (DELETED)
10. ALL PIPING DOWN STREAM OF THE LAST ISOLATION VALVE, AND OPEN TO THE ATMOSPHERE WITH THE SUBSYSTEM DESIGNATION "SYSTEM" (50) THRU (59), SHALL BE CLASSIFIED AS CODE GROUP "D", WITH QUALITY CLASS AND SEISMIC CATEGORY PROVIDED BY THE APPLICABLE NOTES IN THIS DRAWING. EXCEPT WHERE THE APPLICABLE NOTES CALL FOR QUALITY CLASS II+, PIPING SHALL BE QUALITY CLASS II.
11. VALVES RWCU-V-210A&B ARE TO BE INSTALLED WITH THEIR FLOW ARROWS POINTED IN THE DIRECTION OF VALVES RWCU-V-234A&B.
12. LINE NUMBERS IN PARENTHESES DENOTE RWCU-DM-1A SYSTEM INDENTIFICATION.
13. NO UNIQUE LINE NUMBERS GIVEN FOR RWCU(ALL)-1 PIPING AS THESE ARE RADWASTE LINES.
14. ALL INSTRUMENT LINES ARE DESIGNATED BY CODE AND LINE NUMBER.
    a. EXAMPLE: LINES ORIGINATING OUTSIDE CONTAINMENT.
       $\underbrace{\text{1/2"PI(1)-ST}}_{\text{CODE DESIGNATION}}$ - $\underbrace{\text{(H22-P021)-A6}}_{\text{LINE NUMBER}}$
    b. EXAMPLE: LINES ORIGINATING INSIDE CONTAINMENT.
       1/2"PI(1)-4S - X106
       CODE DESIGNATION LINE NUMBER
    c. EXAMPLE: CONTINUATION OF THE ABOVE LINE OUTSIDE CONTAINMENT IS DESIGNATED AS FOLLOWS, WITH LINE NUMBERS NOT SHOWN.
       $\underbrace{\text{1/2"PI(1)-ST-X106}}_{\text{CODE DESIGNATION}}$ - $\underbrace{\text{(H22-P021)}}_{\text{LINE NUMBER}}$
15. CODE BREAK DEFINITIONS FOR THERMOWELLS ARE SHOWN ON M610, "INSTALLATION OF THERMOWELLS AND SAMPLE PROBES."
16. RWCU-PS-114 CONTACTS JUMPERED CLOSED TO INDICATE NORMAL PUMP SUCTION PRESSURE.
17. VALVES RWCU-V-443 AND RWCU-SPV-443 HAVE BEEN DEACTIVATED TO PREVENT INADVERTENT RESIN SPILLS.
18. FOR SAMPLE FUNCTION & INSTRUMENTATION ASSOCIATED WITH THE SAMPLE POINTS SEE DWG. SERIES M607 STEAM & LIQUID SAMPLING FLOW DIAGRAMS AND DWG. SERIES 60A-00 SAMPLE RACKS DETAILS & FLOW DIAGRAMS.
19. SLUDGE LEVEL RWCU-LE-62A AND 62B, RWCU-LS-116A1/A2 AND RWCU-LS-116B1/B2 ARE SPARED IN PLACE. THEY HAVE BEEN HISTORICALLY UNRELIABLE. SLUDGE LEVEL IS PRESENTLY MORE RELIABLY DETERMINED AND CONTROLLED BY USING THE PPM (SOLID WASTE PROCESSING SYSTEM).
20. PRIOR TO 1995 RWCU PROCESS PIPING, PUMPS AND VALVES IN BETWEEN RWCU-V-5A/B AND RWCU-V-40 (BUT NOT INCLUDING THESE VALVES OR SAFETY RELATED INSTRUMENT LINES) WERE ASME III/3. IN 1995 BDC 55-2927-0A RECLASSIFIED THESE VALVES, PUMPS, AND PROCESS PIPING TO ANSI B31.1. FROM 2013 THESE VALVES, PUMPS, AND PROCESS PIPING HAVE BEEN RECLASSIFIED ASME III/3 (REF AR 282022).
21. SEE DWG M501 FOR FLOW DIAGRAM LEGENDS, SYMBOLS AND ABBREVIATIONS.
22. RELIEF VALVES RWCU-RV-1, RWCU-RV-3 & RWCU-RV-36 ARE ASME SECTION VIII QUALITY CLASS II.
23. RWCU-V-34 AND RWCU-V-35 UPSTREAM DISC/WEDGE IS DRILLED (0.25" DIAMETER ±0.005") TO PREVENT PRESSURE LOCKING.

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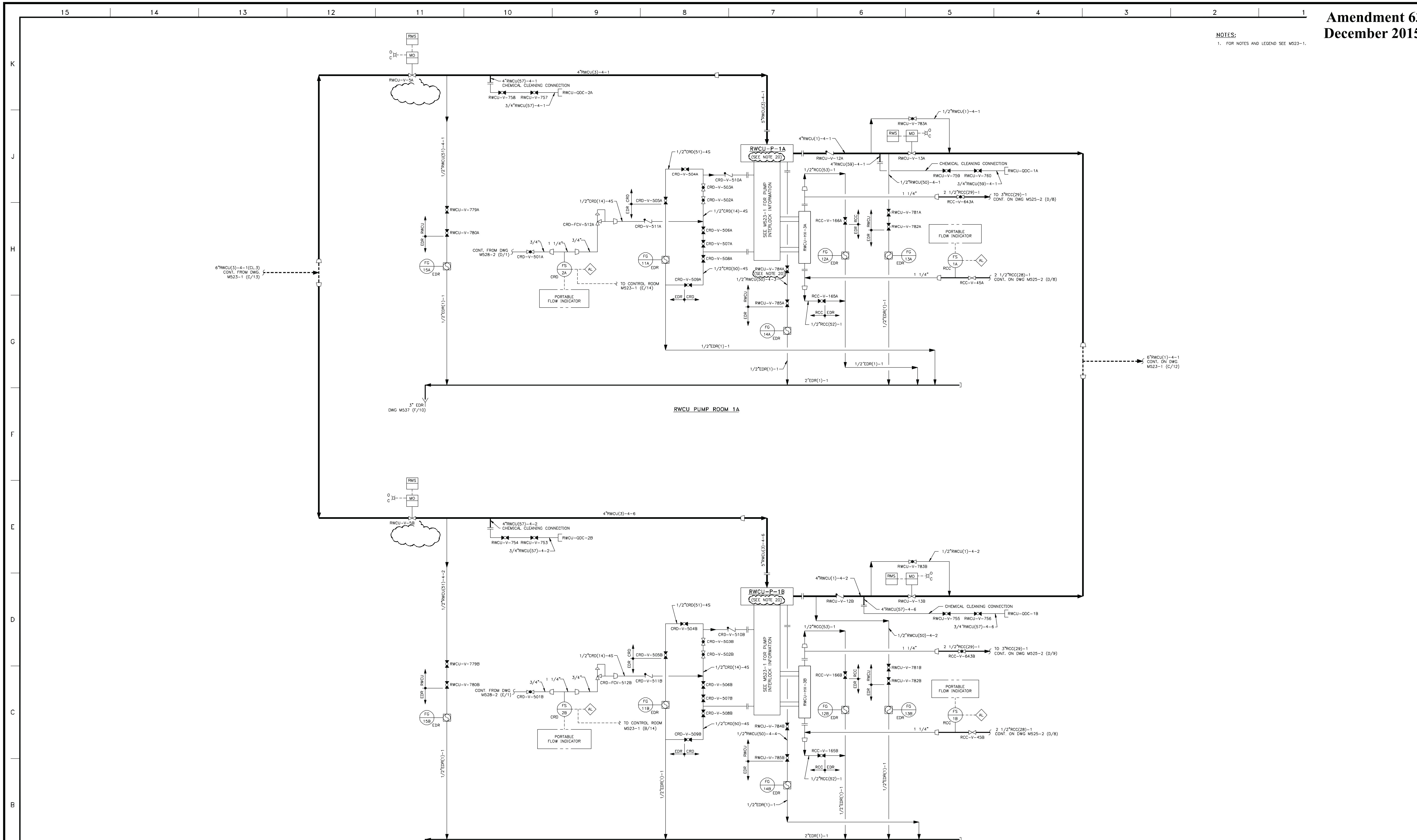
Reactor Water Cleanup System – P&ID

Draw. No. M523-1	Rev. 117	Figure 5.4-22.1

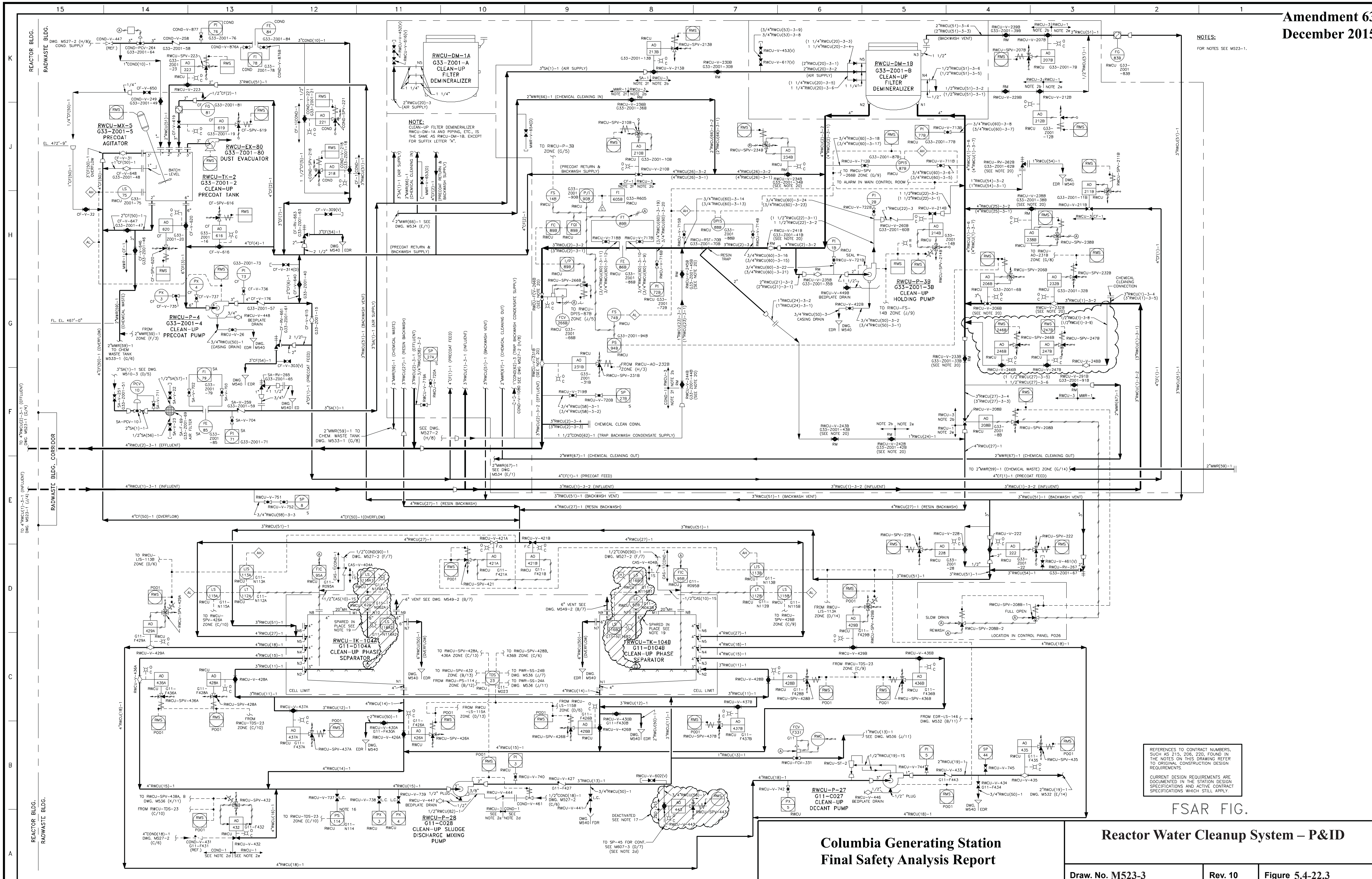


Columbia Generating Station
Final Safety Analysis Report

Reactor Water Cleanup System – P&ID

Draw. No. M523-2 | Rev. 8 | Figure 5.4-22.2

Amendment 63
December 2015



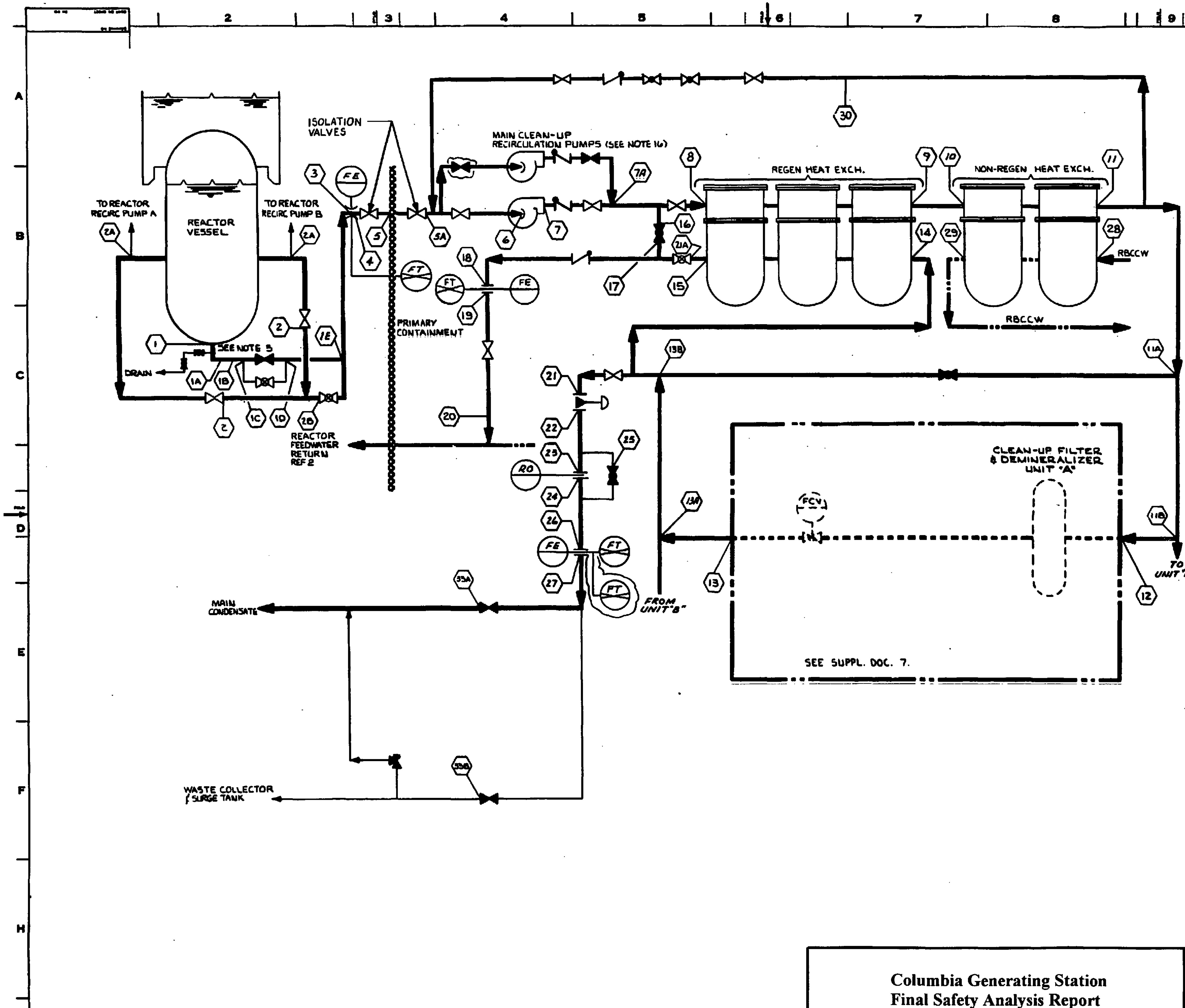
REFERENCES TO CONTRACT NUMBERS, SUCH AS 215, 206, 220, FOUND IN THE NOTES ON THIS DRAWING REFER TO ORIGINAL CONSTRUCTION DESIGN REQUIREMENTS.

CURRENT DESIGN REQUIREMENTS ARE DOCUMENTED IN THE STATION DESIGN SPECIFICATIONS AND ACTIVE CONTRACT SPECIFICATIONS WHICH STILL APPLY.

FSAR FIG.

Columbia Generating Station Final Safety Analysis Report	Reactor Water Cleanup System – P&ID		
	Draw. No. M523-3	Rev. 10	Figure 5.4-22.3

Form No. 960690ai



NOTES:

1. POSITIONS 28 & 29 INDICATE CLEANUP CONDITIONS WITH VARIOUS RBCCW INLET TEMPERATURES.
2. FOR BACKWASH & PRECOAT FREQUENCY SEE SUPPL. DOC. 4 OR 8.
3. FOR DETAILS ON FILTER & DEMINERALIZER SYSTEM SEE PROCESS FLOW DIAGRAM FILTER/DEMINERALIZER SUPPL. DOC. 7.
4. VALVES ARE SHOWN IN THEIR NORMAL OPERATING POSITION.
5. FOR DETAILS OF THE REACTOR VESSEL BOTTOM DRAIN CONNECTIONS SEE SUPPL. DOC. 6.
6. THE MAXIMUM ALLOWABLE PIPE FRICTION DROP FOR THE SIZING OF THE CLEANUP RECIRCULATION PUMPS' SUCTION PIPING FROM POSITIONS 1 THROUGH 4 SHALL BE CONTROLLED BY MODE "B" AND THE NPSH SHALL NOT BE BELOW THE MINIMUM AS SHOWN. MODE "A" SHALL CONTROL THE SIZING OF THE DISCHARGE PIPING AND THE MAXIMUM ALLOWABLE PIPE FRICTION DROP AS SHOWN SHOULD NOT BE EXCEEDED.
7. FOR DATA PERTAINING TO NUMBERS WITHIN HEXAGONS, REFER TO PROCESS DATA SUPPL. DOC. 1.
8. MODE "A" DESIGN BASIS FOR HEAT EXCHANGERS AND NO FLOW IS REQUIRED AT POSITION 16, 17, 21 THROUGH 27.
9. MODE "B" DESIGN BASIS FOR MAIN CLEAN-UP PUMP (MAX. CAPACITY AND MIN. NPSH) AND SIZING OF MAIN PUMPS SUCTION PIPING. NO FLOW REQ'D IN MODE "B" POSITION 8 THROUGH 15 & 21 THROUGH 29.
10. DELETED

NOTES CONTINUED ON SHEET NO. 2

SUPPLEMENTAL DOCUMENTS UNDER THE FOLLOWING IDENTITIES ARE TO BE USED IN CONJUNCTION WITH THIS DRAWING.

		REFERENCE DESIGNATOR
1.	REACTOR WATER CLEAN-UP SYS PROCESS DATA	G33-1030
2.	REACTOR WATER CLEAN-UP SYSTEM P&ID	G33-1010
3.	REACTOR WATER CLEAN-UP SYS DESIGN SPEC.	G33-4010
4.	RADWASTE SYSTEM PD	G11-1020
5.	REACTOR SYSTEM OUTLINE DWG.	A62-2050
6.	REACTOR VESSEL OUTLINE DWG.	B13-D003
7.	FILTER/DEMIN SUBSYS DEVICE LIST ITEM 201	G33-Z001
8.	RADIOACTIVE WASTE	A62-4110
9.	DELETED	
10.	DELETED	

Columbia Generating Station
Final Safety Analysis Report

Reactor Water Cleanup System Process Diagram

Draw. No. 02G33-04,20,1 | Rev. 7 | Figure 5.4-23.1

MODE A NORMAL OPERATION R.S.S. 1020, PSIA SEE NOTES 1,3 AND 9 ON SH. 1

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
FLOW, GPM	63	145	352.	352.	352.	352	352	358.	287.	287.	276.	134.	134.	269.	318.	/	/	318.	318.
TEMP. F.	533.	533.	533.	533.	533.	523.	524.	524.	230.	230.	120.	120.	120.	120.	437.	/	/	437.	437.
MAXIMUM PRESSURE			←1→			←165→TDH		←10→		←10→		←59→		←10→				←4→	
DROP PSID	ALLOWABLE PIPE FRICTION DROPS (SEE NOTE 6 ON SH.1) ←30→																		

(SEE NOTE 14)

LOCATION	20	21	22	23	24	25	26	27	28	29	28	29	28	29	28	29	30.		
FLOW, GPM	318.	/	/	/	/	/	/	/	468.	475.	516.	524.	610.	678.	678.	686.	7.		
TEMP. F.	437	/	/	/	/	/	/	/	85.	150.	95.	154.	100.	150.	105.	150.	120.		
MAXIMUM PRESSURE									←10→		←10→		←10→		←10→				
DROP PSID	←→																		

MODE B HOT SHUTDOWN OPERATION (WITH LOSS OF RPV RECIRC PUMPS). R.S.S. 1003, PSIA SEE NOTES 1 AND 9 ON SH. 1.

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
FLOW, GPM	162.	98.	358.	358	358.	358	358	/	/	/	/	/	/	/	/	358.	358.	358.	358.
TEMP. F.	540.	545.	543.	543.	543.	543.	544.	/	/	/	/	/	/	/	/	544.	544.	544.	544.
MAXIMUM PRESSURE			←1→			←→165.=TDH→										←146→		←4→	
DROPS PSID	ALLOWABLE PIPE FRICTION DROPS SEE NOTE 6 ON SH. 1 ←DELTA P→																		

LOCATION	20	21	22	23	24	25	26	27	28	29									
FLOW, GPM	358.	/	/	/	/	/	/	/	/	/									
TEMP. F.	544.	/	/	/	/	/	/	/	/	/									
MAXIMUM PRESSURE																			
DROP PSID	←→																		

DESIGN PRESSURE & TEMPERATURE GIVEN BELOW IS FOR INFORMATION ONLY AND IS THE BASIS FOR PIPING DESIGN. ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY, ACTUAL LINE SIZES AS DETERMINED BY THE PIPING DESIGNER SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENTS.

LOCATION	1--1A*	1A-1B**	1B-1E	1C-1D	2A-2B	2B-5A	5A-6	7-7A	7A-8	9-10	11-11B	11A-13B	11B-13A	13A-14	13A-33A	15-21A	21A-20	27-33B	
DESIGN PRESS.(PSIG)	1250.	1250.	1250.	1250.	1250.	1250.	1250.	1420.	1420.	1420.	1420.	1420.	1420.	1420.	1420.	1420.	***	1420.	
DESIGN TEMP. (DEG.F)	575.	575.	575.	575.	575.	575.	575.	575.	575.	575.	150.	150.	150.	150.	150.	575.	***	150.	
ESTIMATED LINE SIZE (IN)	2.0	2.5	4.0	1.0	4.0	6.0	3.0	3.0	4.0	4.0	4.0	4.0	3.0	4.0	4.0/6.0	4.0	4.0	4.0	

NOTES:

11. THE MINIMUM REQUIRED NPSH OF THE CLEANUP RECIRC. PUMPS IS 16.0 FEET BASED ON CONDITION SHOWN IN MODE B.
12. SEE PARAGRAPH 4.2.3 OF 23A1678 FOR STARTUP PROCEDURE.
13. DURING HOT STANDBY WITH ONE CLEANUP PUMP IN OPERATION. BLOWDOWN RATE IS APPROXIMATELY 126.0 GPM @ 545 DEGREES F.
14. COOLING WATER FLOW VALUES NOT TO BE EXCEEDED BY MORE THAN 6%.
15. ALL AUXILIARY PIPING IS DESIGNED TO 150. PSIG 150. DEG. F.
16. 100% CAPACITY PUMPS ARE ALTERNATED DURING OPERATIONS.

LEGEND

* LOCATION 1A IS THE POINT WHERE THE BOTTOM DRAIN LINE CONNECTION EXITS FROM THE C.R.D. HOUSING AREA.

** LOCATION 1B IS THE POINT WHERE THE BOTTOM DRAIN LINE CONNECTION EXITS FROM THE REACTOR VESSEL PEDESTAL.

*** TO SAME CONDITIONS AS THE FEEDWATER PIPING (BY OTHERS).

/ INDICATES CONDITIONS FOR 0 FLOW RATE.

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Reactor Water Cleanup System Process Diagram

Draw. No. 02G33-04,20,2 | Rev. 5 | Figure 5.4-23.2

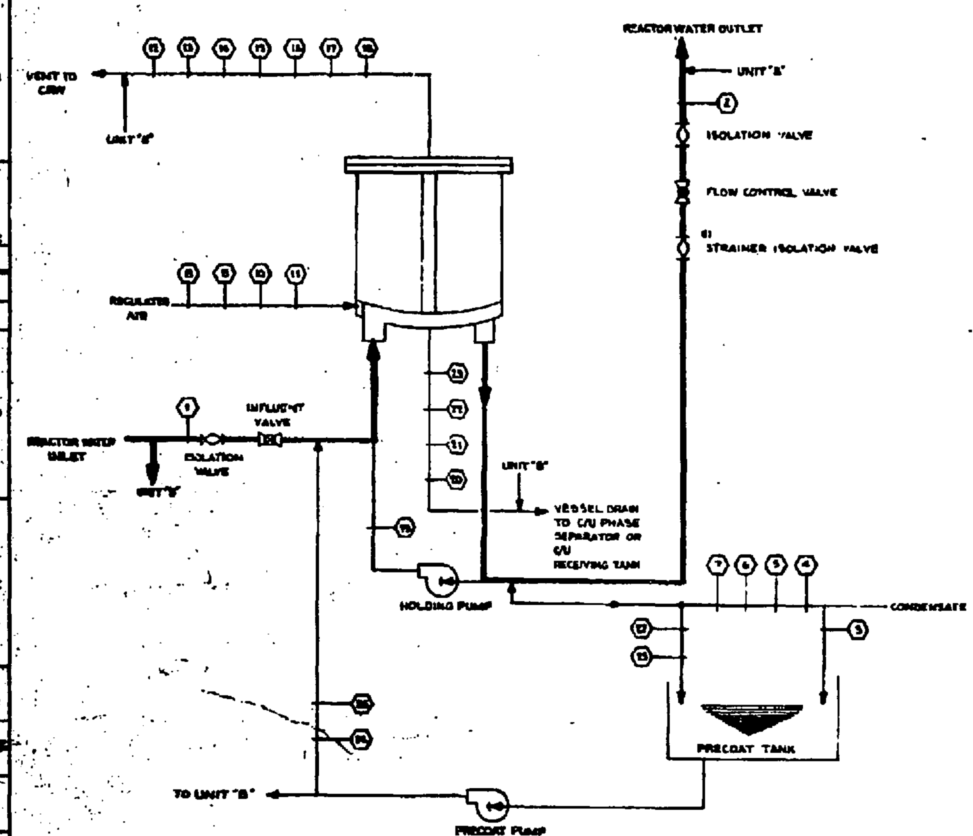

TABLE I (SEE TABLE V) — F/D AREA = 64 FT²

TYPE REQUIREMENT			STATION SERVICES									EXHAUST AIR HANDLING							PROCESS PIPE SIZING								
COMMODITY			CONDENSATE					SERVICE AIR				RADIOACTIVE AIR							REACTOR WATER OR COND	REACTOR WATER + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	SLURRY COND + RESIN	CNDS	CNDS	CNDS
POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PROCESS STEP	NORMAL OPER.	NORMAL OPER.	PRECOAT SLURRY	SLOW BKWSH	FILL & WASH	REWASH	FILL	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	FILL	HOLD	DRAIN	SLOW DRAIN	REWASH	DRAIN	RESIN PRECOAT	PRECOAT RETURN	PRECOAT RETAIN	PRECOAT RETAIN RETURN
PRESSURE, PSIG	SEE NOTE	SEE NOTE	25	25	25	25	25	20	20	10	20	5	5	5	5	5	5	5	[illegible]	20	20	20	20	50	50	50	50
TEMPERATURE, °F			80	80	80	80	80	60	60	60	60	60	60	60	60	60	60	60	80 TO 120	120	80	80	80	60	80	80	60
FLOW RATE			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	100 GPM	100 GPM
FLOW TIME, MIN.	—	—	1.6	10	2	2	10	10	10	2	2	5	10	10	2	2	5	10	—	5	10	2	5	15	15	1	1
TOTAL FLOW	—	—	35 GAL	125 GAL	125 GAL	125 GAL	125 GAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	—	125 GAL	125 GAL	125 GAL	125 GAL	[illegible]	[illegible]	100 GAL	100 GAL
TOTAL LBS SOLIDS	—	—	11.5 ●	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	16 ●	RESIDUAL	RESIDUAL	RESIDUAL	11.5 ●	—	—	—

● SEE NOTE 2

TABLE II (SEE TABLE V) — F/D AREA = 33 FT²

TYPE REQUIREMENT			STATION SERVICES									EXHAUST AIR HANDLING							PROCESS PIPE SIZING								
COMMODITY			CONDENSATE					SERVICE AIR				RADIOACTIVE AIR							REACTOR WATER OR COND	REACTOR WATER + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	SLURRY COND + RESIN	CNDS	CNDS	CNDS
POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PROCESS STEP	NORMAL OPER.	NORMAL OPER.	PRECOAT SLURRY	SLOW BKWSH	FILL & WASH	REWASH	FILL	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	FILL	HOLD	DRAIN	SLOW DRAIN	REWASH	DRAIN	RESIN PRECOAT	PRECOAT RETURN	PRECOAT RETAIN	PRECOAT RETAIN RETURN
PRESSURE, PSIG	SEE NOTE	SEE NOTE	25	25	25	25	25	20	20	20	20	0	5	5	5	5	0	5	[illegible]	20	20	20	20	35	35	35	35
TEMPERATURE, °F			80 TO 120	80	80	80	80	60	60	60	60	60	60	60	60	60	60	60	80 TO 120	120	80	80	80	80	80	80	80
FLOW RATE			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
FLOW TIME, MIN.	—	—	1.5	10	2	2	10	10	10	2	2	5	10	10	2	2	5	10	—	5	10	2	5	15	150	1	1
TOTAL FLOW	—	—	80 GAL	640 GAL	210 GAL	210 GAL	360 GAL	[illegible]	[illegible]	310 SCF	310 SCF	-21 SCF	1560 SCF	[illegible]	[illegible]	[illegible]	-21 SCF	21 SCF	—	1600 GAL	1600 GAL	160 GAL	1600 GAL	[illegible]	[illegible]	[illegible]	136 GAL
TOTAL LBS SOLIDS	—	—	14 ●	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	13 ●	RESIDUAL	RESIDUAL	RESIDUAL	10 ●	—	—	—

● SEE NOTE 2

TABLE III (SEE TABLE V) — F/D AREA = 126 FT²

TYPE REQUIREMENT			STATION SERVICES									EXHAUST AIR HANDLING							PROCESS PIPE SIZING								
COMMODITY			CONDENSATE					SERVICE AIR				RADIOACTIVE AIR							REACTOR WATER OR COND	REACTOR WATER + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	SLURRY COND + RESIN	CNDS	CNDS	CNDS
POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PROCESS STEP	NORMAL OPER.	NORMAL OPER.	PRECOAT SLURRY	SLOW BKWSH	FILL & WASH	REWASH	FILL	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	FILL	HOLD	DRAIN	SLOW DRAIN	REWASH	DRAIN	RESIN PRECOAT	PRECOAT RETURN	PRECOAT RETAIN	PRECOAT RETAIN RETURN
PRESSURE, PSIG	SEE NOTE	SEE NOTE	25	25	25	25	25	20	10	20	20	0	5	5	5	5	0	5	[illegible]	20	20	20	20	35	35	85	95
TEMPERATURE, °F			80 TO 120	80	80	80	80	60	60	60	60	60	60	60	60	60	60	60	80 TO 120	120	80	80	80	80	80	80	80
FLOW RATE			50 GPM	75 GPM	100 GPM	135 GPM	75 GPM	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	85 GPM	75 GPM	135 GPM	83 GPM	505 GPM	505 GPM	600 GPM	600 GPM
FLOW TIME, MIN.	—	—	1.0	10	2	2	10	10	10	2	2	5	10	10	2	2	5	10	—	5	10	2	5	15	15	1	1
TOTAL FLOW	—	—	50 GAL	750 GAL	200 GAL	270 GAL	750 GAL	2000 SCF	2000 SCF	400 SCF	400 SCF	[illegible]	2000 SCF	2000 SCF	400 SCF	400 SCF	[illegible]	210 SCF	—	1750 GAL	750 GAL	1750 GAL	350 GAL	4200 GAL	4200 GAL	200 GAL	600 GAL
TOTAL LBS SOLIDS	—	—	15 ●	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	12 ●	RESIDUAL	RESIDUAL	RESIDUAL	15 ●	—	—	—

● SEE NOTE 2

TABLE IV (SEE TABLE V) — F/D AREA = 157 FT²

TYPE REQUIREMENT			STATION SERVICES									EXHAUST AIR HANDLING							PROCESS PIPE SIZING								
COMMODITY			CONDENSATE					SERVICE AIR				RADIOACTIVE AIR							REACTOR WATER OR COND	REACTOR WATER + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	SLURRY COND + RESIN	CNDS	CNDS	CNDS
POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PROCESS STEP	NORMAL OPER.	NORMAL OPER.	PRECOAT SLURRY	SLOW BKWSH	FILL & WASH	REWASH	FILL	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	FILL	HOLD	DRAIN	SLOW DRAIN	REWASH	DRAIN	RESIN PRECOAT	PRECOAT RETURN	PRECOAT RETURN	PRECOAT RETAIN RETURN
PRESSURE, PSIG	SEE NOTE	SEE NOTE	25	25	25	25	25	20	20	20	20	5	5	5	5	5	5	5	[illegible]	20	20	20	20	50	80	20	90
TEMPERATURE, °F			80	80	80	80	80	60	60	60	60	60	60	60	60	60	60	60	80 TO 120	120	80	80	80	80	80	80	80
FLOW RATE			90 GPM	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
FLOW TIME, MIN.	—	—	2	4	2	2	4	4	2.5	2	2	2.9	4	2.9	2	2	2.9	4	—	2.5	2.5	2	7.5	17	15	1	[illegible]
TOTAL FLOW	—	—	400 GAL	310 GAL	180 GAL	340 GAL	360 GAL	[illegible]	600 SCF	[illegible]	400 SCF	[illegible]	990 SCF	600 SCF	[illegible]	[illegible]	-42 SCF	42 SCF	—	340 GAL	340 GAL	310 GAL	340 GAL	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL LBS SOLIDS	—	—	32 ●	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	42 ●	RESIDUAL	RESIDUAL	RESIDUAL	50 ●	[illegible]	[illegible]	[illegible]

● SEE NOTE 2

NOTES:

1. FOR THESE VALUES AND REMAINDER OF SYSTEM VALUES: SEE REACTOR WATER CLEAN-UP SYSTEM PD.
2. DRY WEIGHT VALUES; AS SHIPPED RESINS CONTAIN 50% MOISTURE (APPROXIMATE).

TABLE V

TABLE	FCF
I	78/E597 GROUP 1 78/E597 GROUP 1
II	[illegible] GROUP 2 [illegible] GROUP 2 [illegible] GROUP 3
III	[illegible] GROUP 3 [illegible] GROUP 3 [illegible] GROUP 2 [illegible] GROUP 1
IV	[illegible] GROUP 1

FILTER/DEMINERALIZER BACKWASH & PRECOATING SEQUENCE

FUNCTIONS:

- SERVICE — 1 2
- ISOLATE & HOLD — 19
- DRAIN — 12 20
- SLOW BACKWASH — 4 8 13
- SLOW DRAIN — 9 14 21
- FILL & WASH — 5 10 15
- REWASH — 6 11 16 22
- DRAIN — 17 23
- FILL — 7 18
- PRECOAT — 3 24
- PRECOAT RETURN — 25
- HOLD UNTIL RETURN TO SERVICE — 26 27
- SERVICE — 1 2

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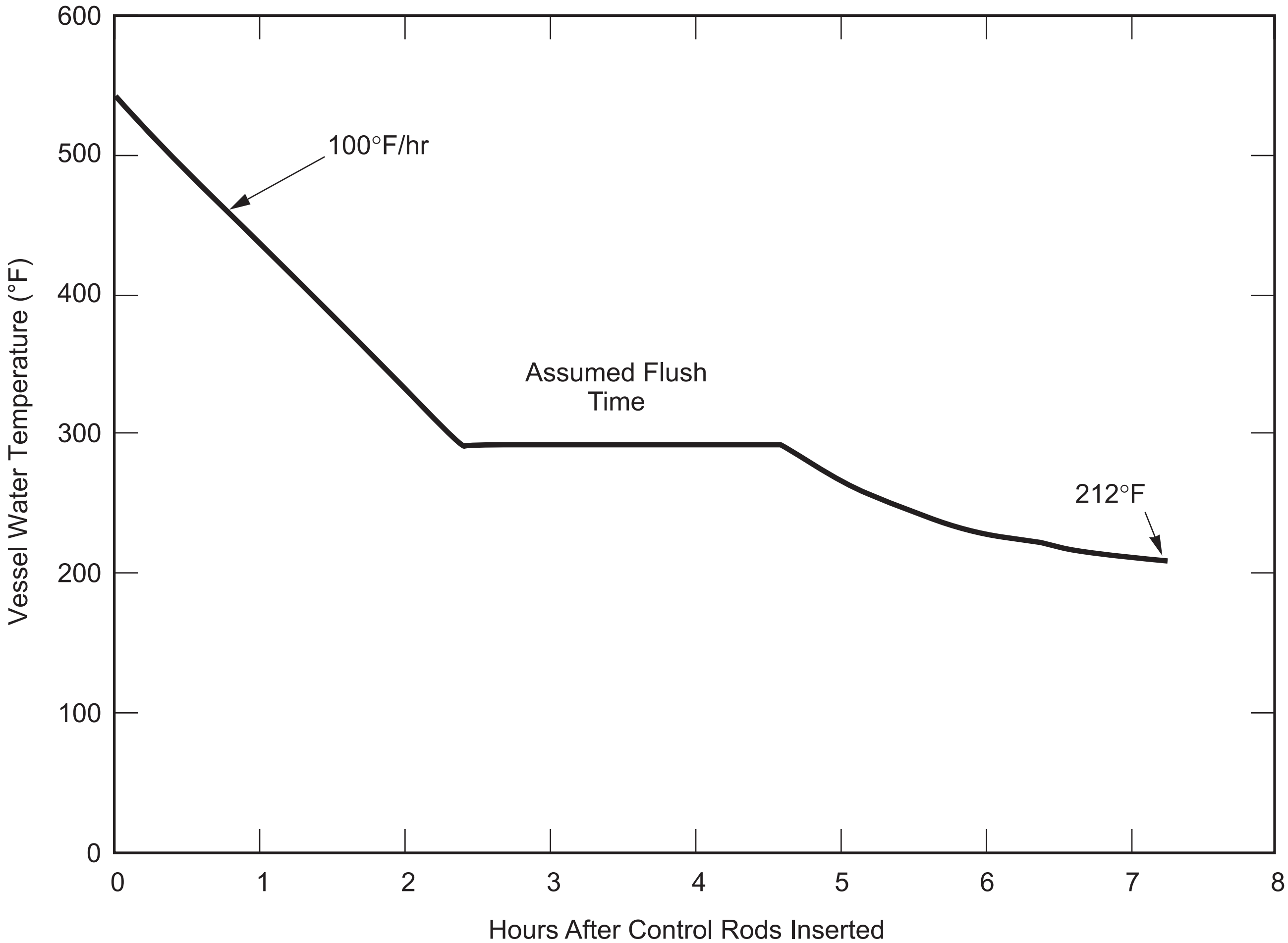
Filter/Demineralization System - P&ID

Draw. No. 02G33-04,14,1 | Rev. 5 | Figure 5.4-24



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Vessel Coolant Temperature Versus Time
(One Heat Exchanger Available)

Draw. No. 960690.92 | Rev. | Figure 5.4-25

Chapter 6

ENGINEERED SAFETY FEATURES

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ENGINEERED SAFETY FEATURES

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Chapter 6

ENGINEERED SAFETY FEATURES

The engineered safety features (ESF) of this plant are those systems provided to mitigate the consequences of postulated serious accidents, in spite of the fact that these accidents are very unlikely. The ESF can be divided into four general groups: containment systems, emergency core cooling systems, habitability systems, fission product removal and control systems. The systems in each general group are

a. Containment systems

   1. Primary containment,
   2. Secondary containment,
   3. Containment heat removal system,
   4. Containment isolation system, and
   5. Combustible gas control.

b. Emergency core cooling systems

   1. High-pressure core spray,
   2. Automatic depressurization system,
   3. Low-pressure core spray, and
   4. Low-pressure coolant injection.

c. Habitability systems

d. Fission product removal and control systems

Related systems which help to mitigate the consequences of such accidents are discussed in other sections. These are

a. Overpressurization protection,
b. Control rod drive housing support systems,
c. Control rod velocity limiter,
d. Main steam line flow restrictor, and
e. Standby liquid control system.

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in the engineered safety feature (ESF) components have been evaluated to ensure that material interactions will not occur that could potentially impair operation. Materials have been selected to withstand the environmental conditions encountered during normal operation and postulated accidents. Their compatibility with core and containment spray solutions has been considered and the effects of radiolytic decomposition products have been evaluated.

Coatings used on exterior surfaces within the primary containment are suitable for the environmental conditions expected. Nonmetallic thermal insulation is required to have the proper ratio of leachable sodium plus silicate ions to leachable chloride ions to minimize the possibility of stress corrosion cracking.

6.1.1 METALLIC MATERIALS

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Material Specifications

Table 5.2-7 lists the principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components. Table 6.1-1 lists the principal pressure retaining materials and the appropriate material specifications for the ESF of the plant.

6.1.1.1.2 Compatibility of Construction Materials with Core Cooling Water and Containment Sprays

The compatibility of the reactor coolant with materials of construction exposed to the reactor coolant is discussed in Section 5.2.3. These same materials of construction are found in the ESF components.

Demineralized water with no additives is employed in BWR core cooling water and containment sprays. No detrimental effects will occur on the ESF construction materials from allowable contaminant levels in this high purity water.

6.1.1.1.3 Controls for Austenitic Stainless Steel

a. Control of the use of sensitized stainless steel

   Wrought austenitic stainless steels that have been heated to temperatures over 800°F by means other than welding or thermal cutting are either resolution

annealed or otherwise demonstrated to be unsensitized in accordance with Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel.

Controls to avoid significant sensitization discussed in Section 5.2.3 are the same for ESF components.

b. Process controls to minimize exposure to contaminants

Process controls for austenitic stainless steel discussed in Section 5.2.3 are the same for ESF components.

c. Use of cold worked austenitic stainless steel

Austenitic stainless steel with a yield strength greater than 90,000 psi was not used in ESF systems with the exception of screen material in the emergency core cooling system (ECCS) suppression pool strainers. Fabrication of the screens entailed operations that cold-worked the screen material (i.e., punching, drilling, de-burring, and/or forming). The cold-working caused yield stresses, as determined by hardness testing, to exceed 90,000 psi. The screens were found to be acceptable due to their nonpressure retaining function and the controlled chemistry and pool temperature of the suppression pool.

d. Thermal insulation requirements

All thermal insulation materials in ESF systems were selected, procured, tested, stored, and installed in accordance with Regulatory Guide 1.36, Revision 0. The leachable concentrations of chlorides, fluorides, sodium, and silicates for nonmetallic thermal insulation for austenitic stainless steel were required to meet the requirements of Regulatory Guide 1.36, Revision 0. Certified reports and test reports for the materials are available.

e. Avoidance of hot cracking of stainless steel

Process controls to avoid hot cracking discussed in Section 5.2.3 are the same for ESF components.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

Containment spray and core cooling water for the ESF systems are supplied from the condensate storage tanks or the suppression pool.

The quality of the water stored in the condensate storage tanks is maintained as follows:

Conductivity*	1 µS/cm at 25°C
Chlorides	0.05 ppm
pH*	6 to 8 at 25°C
Boron (as BO_3)	0.1 ppm

The suppression pool is initially filled with high-purity water from either the condensate storage or demineralized water makeup system. The chloride concentration in the suppression pool water is maintained at less than 0.5 ppm Cl. To maintain suppression pool water quality, provision is made for periodic filtration and demineralization using the fuel pool filter demineralizer or by means of blowdown and reprocessing through the radwaste treatment system.

6.1.2 ORGANIC MATERIALS

Significant quantities of organic materials that exist within the primary containment consist of cable insulating material, motor insulation material and coatings for containment surfaces, equipment, and piping.

Insulation properties for electric power cable are discussed in Section 8.3.1.2.3. Motors for the reactor recirculation pumps and drywell fan coil units contain small quantities of lubricating oil. Motor-operated valve bearings are grease lubricated.

Equipment, piping, and primary surfaces are provided with various coatings including galvanized zinc and aluminum. A minimal amount of hydrogen is liberated from zinc paint, galvanized, radiolytic and thermal decomposition of organic materials. Since Columbia Generating Station (CGS) is an oxygen control plant with an inerted containment, the hydrogen concentration is not flammable. Therefore, the minimal amount of hydrogen potentially generated by organic materials is not a threat to containment integrity.

The suppression chamber (wetwell) above the water level from el. 472 ft 0 in. is coated with one coat of Dimetcote 6 (inorganic zinc). Approximately 4000 ft^2 of this coating do not meet ANSI N101.4 requirements because of damage. The damage to the coating will not result in the failure of the coating to adhere to its substrate. Regardless, the design of the ECCS strainers assumes the complete failure of the coating system and the entrainment of the resulting particles on the strainer bed following a LOCA.

Coatings on insulated piping that were damaged during construction were not repaired, and the insulation will contain any flakes which may form.

* Conductivity and pH limits apply after correction for dissolved CO_2.

In general protective coatings, except NSSS vendor-supplied equipment and valve contracts placed prior to issuance of Regulatory Guide 1.54, Revision 0, have been applied in accordance with the guidelines included in ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." In addition, the coatings and coating systems used meet the requirements of ANSI N101.2-1972 for the design basis accident. Certain items of equipment in the drywell have been coated with unqualified organic paint. There are an estimated 5000 ft^2 of unqualified organic paint in the drywell. Under certain postaccident conditions, the unqualified organic paint could fail in flakes and, therefore, has been evaluated as a potential source of debris which can clog emergency core cooling suction strainers. It is unlikely that all paint would fail simultaneously or that a significant portion of resulting paint flakes would be transported to the suppression pool. For conservatism, however, the design of the ECCS strainers is based on the complete failure of the unqualified coatings, their transport to the wetwell, and their eventual entrainment on the strainer beds.

6.1.3 POSTACCIDENT CHEMISTRY

Since the water chemistry conditions of the reactor coolant are similar to suppression pool water, with the exception being the addition of activation, corrosion, and fission products, no appreciable pH changes are expected to occur during the LOCA transient.

There are no soluble acids and bases within the primary containment that would change post-LOCA water chemistry. Since the pH does not change appreciably there are no detrimental effects on containment equipment or structures.

The design basis source term LOCA accident requires the addition of sodium pentaborate solution post-accident to maintain the suppression pool pH equal to or greater than 7.0. The Standby Liquid Control (SLC) tank contents are injected and mixed in the suppression pool within 8 hours post-accident. This action is discussed in the dose consequences analysis in Section 15.6.5.

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials

Component	Form	Material	Specification (A/SA)[a]
RHR heat exchanger			
Head and shell	Plate	Carbon steel	516 Grade 70
Flanges and nozzles	Forging	Carbon steel	105 Grade 2
Tubes	U-Tube	Stainless steel	249 Type 304L
Tube sheet	Forging	Carbon steel	105 Grade 2
Bolts	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
RHR pump			
Shell and dished head	Plate	Carbon steel	516 Grade 70
Suction nozzle	Pipe	Carbon steel	333 Grade 6
Flange	Forging	Carbon steel	350 Grade LF2
Impeller	Casting	Stainless steel	296 CA15
Shaft	Bar	Stainless steel	276 Type 410
Shell/suction/discharge plate	Plate	Carbon steel	516 Grade 70
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
HPCS pump			
Shell and dished head	Plate	Carbon steel	516 Grade 70
Flange	Plate	Carbon steel	516 Grade 70
Discharge elbow	Pipe	Carbon steel	234 Grade WPB
Impeller	Casting	Stainless steel	296 CA15 or A487 CA6NM CL A
Shaft	Bar	Stainless steel	276 Type 410
Shell/suction/discharge plate	Plate	Carbon steel	516 Grade 70
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
LPCS pump			
Shell and dished head	Plate	Carbon steel	516 Grade 70
Suction nozzle	Pipe	Carbon steel	333 Grade 6
Flange	Forging	Carbon steel	350 Grade LF2
Elbow	Pipe	Carbon steel	234 Grade WPB
Impeller	Casting	Stainless steel	296 CA15

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
LPCS pump (Continued)			
Shaft	Bar	Stainless steel	276 Type 410
Shell/suction/discharge plate	Plate	Carbon steel	516 Grade 70
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
HPCS valves			
Body, bonnet	Casting	Carbon steel	216 Grade WCB
	Forging	Carbon steel	105 or 105 Grade 2
Disc	Casting	Carbon steel	216 Grade WCB
	Casting	Alloy steel	217 Grade WC6
	Forging	Carbon steel	105 or 105 Grade 2
Stem	Bar	Stainless steel	479 Type 410
	Bar	Stainless steel	461 Grade 630
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
	Bar	Carbon steel	194 Grade 2H
Isolation valves			
Body	Casting	Carbon steel	216 Grade WCB
	Forging	Stainless steel	182 Grade F316
	Forging	Carbon steel	350 Grade LF2
	Forging	Carbon steel	105 Grade 2
Bonnet	Forging	Carbon steel	105 Grade 2
	Casting	Carbon steel	216 Grade WCB
	Forging	Carbon steel	350 Grade LF2
Disc	Forging	Alloy steel	182 Grade F11
	Forging	Stainless steel	182 Grade F316
	Casting	Carbon steel	216 Grade WCB
	Forging	Carbon steel	105
	Forging	Carbon steel	350 Grade LF2
Stem	Bar	Stainless steel	276 Type 410
	Bar	Stainless steel	479 Type 410
	Bar	Stainless steel	564 Type 630
	Bar	Stainless steel	461 Grade 630
	Forging	Stainless steel	182 Grade F6a
Stud	Bar	Alloy steel	540 Grade B23
	Bar	Alloy steel	193 Grade B7

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
Isolation valves (Continued)			
Nuts	Bar	Alloy steel	194 Grade 7
	Bar	Carbon steel	194 Grade 2H
Safety relief valves			
Body and bonnet	Forging	Carbon steel	105 Grade 2
Disc holder	Forging	Inconel 718	MS 5662B
Shaft	Bar	Stainless steel	582 Type 416
Spindle	Bar	17-4 pH (H1085)	564 Type 630
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Carbon steel	194 Grade 2H
	Bar	Alloy steel	194 Grade 7
Standby liquid control pump			
Fluid cylinder	Forging	Stainless steel	182 Grade F304
Cylinder head, valve cover, and stuffing box flange plate	Plate	Stainless steel	240 Type 304
Cylinder head extension, valve stop, and stuffing box	Shapes	Stainless steel	479 Type 304
Stuffing box gland and plungers	Bar	17-4 pH (H1075)	564 Grade 630
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
Standby liquid control explosive valve			
Body and fittings	Shapes	Stainless steel	479 Type 304
Flanges	Forging	Stainless steel	182 Grade F304
Pipe	Pipe	Stainless steel	312 Type 304
Control rod velocity limiter			
	Casting	Stainless steel	351 Grade CF8 or 351 Grade CF3
Main steam flow restrictor			
Upstream part	Casting	Stainless steel	351 Grade CF8
Downstream part	Casting	Carbon steel	216 Grade WCB

Table 6.1-1

Engineered Safety Features Systems and Related Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
Piping			
HPCS	Pipe	Carbon steel	106 Grade B
LPCS	Pipe	Carbon steel	106 Grade B
RHR (unless otherwise noted)	Pipe	Carbon steel	106 Grade B
RHR connection to RRC	Pipe	Stainless steel	312 Type 304 or
	Pipe	Carbon steel	333 Grade 1 or 6
RHR spray headers	Pipe	Carbon steel	333 Grade 1 or 6
SRV discharge line	Pipe	Carbon steel	333 Grade 1 or 6
24-in. downcomer vents	Pipe	Carbon steel	106 Grade B or C and 312 Type 304L or 316L (bottom 6 in. only)
28-in. downcomer vents	Pipe	Carbon steel	155 KC70 Class 2 and 312 Type 304L or 316L (bottom 4 in. only)
	Fittings	Carbon steel	181 Grade II
	Fittings	Carbon steel	234 Grade WPB
	Fittings	Stainless steel	182 Grade F304
	Fittings	Stainless steel	182 Grade WP304
Containment			
Vessel	Plate	Carbon steel	516 Grade 70
	Plate	C-Mn-Si steel	537 Class 1
Structural members	Plate	Carbon steel	36
Downcomer bracing	Pipe	Carbon steel	106 Grade B
	Rings	Carbon steel	572 Grade 60
Pipe restraints	Plate	Carbon steel	516 Grade 70
Penetration nozzle	Pipe	Stainless steel	312 Grade TP 304
	Pipe	Carbon steel	333 Grade 1 or 6

Table 6.1-1

Engineered Safety Features Systems and Related Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
Containment (Continued)			
Guard pipe	Pipe	Carbon steel	333 Grade 1 or 6
Flued head	Forging	Carbon steel	350 Grade 1 Fl or 2
Drywell floor seal	Pipe	Stainless steel	312 Type 304L

[a] SA materials for ASME Section III pressure boundary item.

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Pressure Suppression Containment

6.2.1.1.1 Design Basis

The pressure suppression containment system, including subcompartments, meets the following functional capabilities:

a. The containment has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures which would occur following any postulated loss-of-coolant accident (LOCA). The LOCA includes the worst single failure (which leads to maximum containment pressure and temperature) and is further postulated to occur simultaneously with loss of offsite power. In developing the load combinations, a safe shutdown earthquake (SSE) is postulated to occur simultaneously with the LOCA;

b. The containment in combination with other accident mitigation systems limits fission product leakage during and following the postulated design basis accident (DBA) to values less than leakage rates which would result in offsite doses greater than those set forth in 10 CFR 50.67;

c. The containment system will withstand coincident fluid jet forces associated with the flow from the postulated rupture of any pipe within the containment;

d. The containment design permits removal of fuel assemblies from the reactor core after the postulated LOCA;

e. The containment system is protected from or designed to withstand missiles from internal sources and excessive motion of pipes which could directly or indirectly endanger the integrity of the containment;

f. The containment system provides means to channel the flow from postulated pipe ruptures in the drywell to the pressure suppression pool;

g. The containment system is designed to allow for periodically conducting tests at the peak pressure calculated to result from the postulated DBA to confirm the leaktight integrity of the containment and its penetrations; and

h. The containment system, which includes the wetwell-to-drywell and the reactor building-to-wetwell vacuum breaker systems, can withstand the maximum

calculated external pressure on the containment vessel and upward pressure on the drywell floor due to containment spray actuation under the most severe conditions.

6.2.1.1.2 Design Features

A general description of the primary containment and its compliance with applicable codes, standards and guides is given in Section 3.8.2. The design of the primary containment incorporates the following:

a. Protection against dynamic effects

The design of the containment takes into account dynamic effects such as pipe whip, missiles, and jet loads which could result from a postulated LOCA. The design ensures that the capability of the containment and other engineered safety feature (ESF) equipment which mitigate the consequences of an accident are not impaired by the dynamic effects of the accident. The design provisions are discussed in Section 3.8.2.

The capability of the primary steel containment vessel to withstand the hydrodynamic effects of safety/relief valve (SRV) actuation or a LOCA and the proposed modifications, if any, for those portions and components of the vessel which are determined to have insufficient capability to accommodate these hydrodynamic effects are discussed in References 6.2-7 and 6.2-8.

b. Pressure suppression

The primary containment conforms to the fundamental principles of a MKII pressure suppression system. A comparison of the containment with similar containments is made in Table 1.3-4. The water stored in the suppression pool is capable of condensing the steam displaced into the wetwell through the downcomer vents, and the amount of water is sufficient such that operator action is not required for at least 10 minutes immediately following initiation of a LOCA. In addition, the design allows the water from any pipe break within the primary containment to drain back to the suppression pool. This "closed loop" ensures a continuous, adequate supply of water for core cooling.

c. Negative loading

The primary containment is designed for the following negative loadings:

1. A drywell pressure of 2.0 psi below reactor building pressure,
2. A wetwell pressure of 2.0 psi below reactor building pressure, and

3. An upward pressure across the diaphragm floor of 6.4 psid.

The nine 24-in. wetwell-to-drywell (WW-DW) and the three 24-in. reactor building-to-wetwell (RB-WW) vacuum breaker lines are sized to ensure that negative loadings are not exceeded. The vacuum breaker systems are described in Section 3.8.2.

The primary containment is designed for a total external pressure of 4 psid. However, since the compressed insulation between the concrete biological shield and the containment exerts a uniform 2 psid external pressure (half of the total external pressure differential allowed) the drywell pressure may be no less than 2 psi below the reactor building pressure.

d. Environmental conditions

The means to maintain the required environmental conditions inside the primary containment during normal operation is discussed in Section 6.2.1. With the exception of energy removal from the suppression pool, there are no requirements for environmental controls during a LOCA. All equipment required to mitigate the consequences of an accident is designed to perform the required functions for the required duration of time in the accident environment. The equipment accident environment is listed in Table 3.11-2.

e. Insulation

Inside the primary containment, the type of thermal insulation used for piping is primarily reflective metal panel. Nonmetallic mass insulation may also be used, in limited applications, where configuration of the component to be insulated precludes the use of reflective insulation (i.e., at pipe whip restraints, pipe supports, and interferences), and as stop gaskets between circumferential joints of reflective insulation. Also, nonmetallic insulation has been used to expedite the replacement of damaged reflective insulation panels when as low as is reasonably achievable (ALARA) considerations apply.

Reflective metal insulation panels used for the pipes are typically 2 ft long, 3 in. to 4 in. thick, and cover half of the pipe's circumference. These panels have 24-gauge stainless steel sheets which fully encase the 6 mil aluminum sheets. The panels used for the reactor pressure vessel (RPV) are larger, typically 2 ft x 6 ft, and are encased by 18-gauge stainless steel.

Panels on piping covering areas which require inservice inspection, such as welds, are fastened by quick-release buckle bands. Nonremovable insulation panels around pipes are fastened. The fasteners have been designed to be

weaker than the panels; therefore, it is postulated that some panels near a pipe break will be blown away, but that the panels themselves will not be sheared open.

The insulation panels and nonmetallic mass insulation that may be blown off constitute a credible debris source within the primary containment following a LOCA and seismic event. Equipment within the primary containment, if not designed to Seismic Category I standards, is at least supported so as to remain fastened during a seismic event.

Large pieces of insulation debris could be lodged against the perimeter of the jet deflectors, but the square footage of panels blown off the piping would not be sufficient to result in significant blockage of the downcomers. If metallic or nonmetallic insulation were blown off in a pipe break accident, it is probable that most debris would remain in large pieces and would be lodged against piping, equipment, or grating before it reached the drywell floor, or remain on the floor or be lodged against the jet deflector stiffener plates rather than be swept through the downcomers into the suppression pool. Insulation fibers and bits of foil liberated by the rupture has a higher potential of reaching the suppression pool, either during the immediate aftermath of the rupture or in the subsequent washdown by the containment sprays.

Insulation that is transported to the suppression pool could affect the performance of strainers in the wetwell. For this reason, the design of the strainers uses the following conservative bases:

1. Unlimited amounts of reflective metal insulation will be transported to the suppression pool;

2. Dependent on location in the drywell, from 21% to 76% of nonmetallic (fibrous) insulation dislodged by a pipe rupture event is transported to the wetwell. The higher transport percentage, 76%, is used when dislodged insulation is below drywell grating that would hinder the transport of insulation to the wetwell; and

3. All metallic and fibrous insulation that reaches the suppression pool following a LOCA is assumed to be entrained on the beds of operating ECCS strainers.

Straıners on the RHR and LPCS suction lines are located at a centerline of 11 ft 9 in. to 12 ft 4 in. above the pool bottom. The HPCS suction strainers are located 3 ft 6 in. above the pool bottom. These strainers are designed to operate with their beds entrained with the insulation and debris postulated in the

suppression pool following a LOCA. Based on the above, neither the metallic insulation panels nor the nonmetallic mass insulation will cause the degradation of the ECCS systems due to clogging of suction strainers. The analysis is discussed in Section 6.3.2.2.6.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Summary Evaluation. The key design parameters for the pressure suppression containment are shown in Table 6.2-1.

The design parameters are not determined from a single event but from an envelope of accident conditions.

A maximum drywell and suppression chamber pressure occurs near the end of a blowdown phase of a LOCA. Approximately the same peak pressure occurs for either the break of a recirculation line or a main steam line. Both accidents are evaluated.

The most severe drywell temperature condition (peak temperature and duration) occurs for a small primary system rupture above the reactor water level that results in the blowdown of reactor steam to the drywell (small steam break). To demonstrate that breaks smaller than the rupture of the largest primary system pipe will not exceed the containment design parameters, the containment system responses to an intermediate size liquid break and a small size steam break are evaluated. The results show that the containment design conditions are not exceeded for these smaller break sizes.

A single recirculation loop operation (SLO) containment analysis was performed. The peak wetwell pressure, diaphragm download and pool swell containment responses were evaluated over the entire SLO power/flow region.

The highest peak wetwell pressure during SLO occurred at the maximum power/flow condition of 73.8% power/64.3% core flow. This peak wetwell pressure decreased by about 1% (0.5 psi) compared to the rated two-loop operation pressure. The diaphragm floor download and pool swell velocity evaluated at the worst power/flow condition during SLO were found to be bounded by the rated power analysis.

The analytical results and method of analysis utilized to determine the seismic sloshing effects in the wetwell are discussed in Section 3.8.2.

6.2.1.1.3.2 Containment Design Parameters. Table 6.2-1 provides a listing of the key design parameters of the primary containment system including the design characteristics of the drywell, suppression pool, and pressure suppression vent system.

The downcomer loss coefficient is 2.77. This value was used in the assessment of the limiting containment performance analysis. The nonlimiting events not reanalyzed for the power uprate assumed a loss of coefficient of 1.9.

There are eighty-four 24-in. diameter downcomers and eighteen 28-in. downcomers. Three of the downcomers are capped.

No known studies have been performed to experimentally determine 4T test downcomer vent loss coefficients. However, in Pool Swell Analytical Model (PSAM)/4T test data comparisons (References 6.2-27 and 6.2-28), General Electric (GE) used downcomer vent loss coefficients of 2.51 and 3.50 for the 4T test 20-in. downcomers and 24-in. downcomers, respectively. These values were used as input to the GE PSAM and were calculated using information from Reference 6.2-15. The Columbia Generating Station (CGS) downcomer friction loss coefficient (fl/D) that is used in pool swell studies is equal to 1.9 (see Table 3.8-1). Use of a value of 1.9 versus a 4T value ensures conservatism in CGS pool swell studies in that lower values of fl/D maximizes pool swell velocity (see Figure 4-24 of Reference 6.2-5).

Table 6.2-2 provides the performance parameters of the related ESF systems which supplement the design conditions of Table 6.2-1 for containment cooling purposes during post blowdown long-term accident operation. Performance parameters given include those applicable to full capacity operation and to those conservatively reduced capacities assumed for containment analyses.

In addition to the power uprate analysis (Reference 6.2-35), an additional containment analysis was performed (Reference 6.2-42) to evaluate reduced ECCS flow rates (RHR/LPCI and LPCS). Tables 6.2-2 through 6.2-6 detail this analysis. The power uprate analysis remains bounding.

Additionally, Reference 6.2-42 documents an analysis to address General Electric (GE) Safety Communication (SC) 06-01. GE SC 06-01 indicated that long-term low-pressure injection with all pumps operating and one RHR heat exchanger inoperable may impact suppression pool temperature. The analysis concludes that, when only one RHR heat exchanger is operable, two LPCI pumps and the LPCS pump must be secured. The timing for this action is detailed in Reference 6.2-42. This action is required to not exceed the bounding suppression pool temperature of 204.5°F.

6.2.1.1.3.3 Accident Response Analysis. The containment functional evaluation was initially based on the consideration of several postulated accident conditions resulting in release of reactor coolant to the containment. These accidents include

a. An instantaneous guillotine rupture of a recirculation line,
b. An instantaneous guillotine rupture of a main steam line,
c. An intermediate size liquid line rupture, and

d. A small size steam line rupture.

The containment response to the main steam line, intermediate liquid line, and small size steam line breaks, were bounded by the recirculation line break. As part of the evaluations to support the reactor power uprate to 3486 MWth (References 6.2-32, 6.2-33, and 6.2-35), only the recirculation line rupture (Case C), the bounding event for containment response, was reanalyzed. The containment response analyses are not cycle specific nor are they part of the analyses performed to support core reload analyses. For further discussion, see Sections 6.2.1.1.3.3.4 and 6.2.1.1.3.3.5.

For the containment analysis performed to evaluate reduced ECCS flow rates (RHR/LPCI and LPCS), the recirculation line rupture (Cases A, B, and C) were re-analyzed. For further discussion, see Section 6.2.1.1.3.2.

6.2.1.1.3.3.1 Recirculation Line Rupture. Immediately following the rupture of the recirculation line, the flow out both sides of the break will be limited to the maximum allowed by critical flow consideration. Figure 6.2-2 shows a schematic view of the flow paths to the break. In the side adjacent to the suction nozzle, the flow will correspond to critical flow in the pipe cross section. In the side adjacent to the injection nozzle, the flow will correspond to critical flow at the 10 jet pump nozzles associated with the broken loop. In addition, the cleanup line cross tie will add to the critical flow area. Table 6.2-3 provides a summation of the break areas. References 6.2-1 and 6.2-2 provide a detailed description of the analytical models and assumptions for this event.

6.2.1.1.3.3.1.1 Assumptions for Reactor Blowdown. The response of the reactor coolant system during the blowdown period of the accident is analyzed using the following assumptions:

a. The initial conditions for the recirculation line break accident are such that the system energy is maximized and the system mass is minimized. That is

   1. For the nonlimiting events which were not reanalyzed for power uprate, the reactor is operating at 104.2% of maximum power (3323 MWt). This maximizes the postaccident decay heat.

   2. For the limiting events, the reactor is operating at 3702 MWt. This power corresponds to 102% of 3629 MWt. The analysis power was chosen to support a future uprate to 3629 MWt and bounds a power uprate to 3544 MWt (current).

   3. For the containment analysis performed to evaluate reduced ECCS flow rates (RHR/LPCI and LPCS), the reactor is operating at 3556 MWt.

This power corresponds to 100.34% of 3544 MWt. ANS 5.1-1979+2σ with GE Service Information Letter (SIL) 636 is used to determine decay heat release.

4. For the nonlimiting events which were not reanalyzed for power uprate, the standby service water (SW) temperature is assumed to be 95°F, which exceeds the maximum expected temperature. For power uprate, a less conservative value of 90°F was assumed. For the containment analysis performed to evaluate reduced ECCS flow rates (RHR/LPCI and LPCS), 85°F is assumed for the first 10 hours and 90°F thereafter.

5. The suppression pool mass is at the low water level.

6. The suppression pool temperature is assumed to be at the maximum value allowed for power operation.

b. The recirculation line is considered to be severed instantly. This results in the most rapid coolant loss and depressurization of the vessel, with coolant being discharged from both ends of the break.

c. Reactor power generation ceases at the time of accident initiation because of void formation in the core region. Scram also occurs in less than 1 sec from receipt of the high drywell pressure signal. The difference between the shutdown times is negligible.

d. The vessel depressurization flow rates are calculated using Moody's critical flow model (Reference 6.2-3) assuming "liquid only" outflow, since this assumption maximizes the energy releases to the drywell. "Liquid only" outflow implies that all vapor formed in the RPV by bulk flashing rises to the surface rather than being entrained in the existing flow. In reality, some of the vapor would be entrained in the break flow which would significantly reduce the RPV discharge flow rates. Further, Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximizes slip ratio, accurately predicts vessel outflows through small diameter orifices. Actual rates through larger flow areas, however, are less than the model indicates because of the effects of a near homogeneous two-phase flow pattern and phase nonequilibrium. These effects are conservatively neglected in the analysis.

e. The core decay heat and the sensible heat released in cooling the fuel to approximately 550°F are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization period. The resulting high-energy

release rate causes the RPV to maintain nearly rated pressure for approximately 20 sec. The high RPV pressure increases the calculated blowdown flow rates which is again conservative for analyses purposes. The sensible energy of the fuel stored at temperatures below approximately 550°F is released to the vessel fluid along with the stored energy in the vessel and internals as vessel fluid temperatures decrease below approximately 550°F during the remainder of the transient calculation.

f. The main steam isolation valves (MSIV) start closing at 0.5 sec after the accident. They are fully closed in the shortest possible time of 3 sec following closure initiation. In actuality, the closure signal for the MSIV will occur from low reactor water level, so the valves will not receive a signal close for at least 4 sec, and the closing time may be as long as 5 sec. By assuming rapid closure of these valves, the RPV is maintained at a high pressure, which maximizes the calculated discharge of high-energy water into the drywell. For the containment analysis performed to evaluate reduced ECCS flow rates (RHR/LPCI and LPCS), MSIV closure was assumed to start at 0 seconds after the accident.

g. For the nonlimiting events which are not reanalyzed for power uprate, reactor feedwater flow was assumed to stop instantaneously at time zero. Since feedwater flow tends to depressurize the RPV, thereby reducing the discharge of steam and water into the drywell, this assumption is conservative for the analysis since MSIV closure cuts off motive power to the steam-driven feedwater pumps.

For the limiting events, reactor feedwater flow is assumed to continue until all high-energy feedwater is injected into the reactor.

h. A complete loss of offsite power occurs simultaneously with the pipe break. This condition results in the loss of power conversion system equipment and also requires that all vital systems for long-term cooling be supported by onsite power supplies.

6.2.1.1.3.3.1.2 Assumptions for Containment Pressurization. The pressure response of the containment during the blowdown period of the accident is analyzed using the following assumptions:

a. Thermodynamic equilibrium exists in the drywell and suppression chamber. Since nearly complete mixing is achieved, the analysis assumes complete mixing;

b. The fluid flowing through the drywell-to-suppression pool vents is formed from a homogeneous mixture of the fluid in the drywell. The use of this assumption results in complete carryover of the drywell air and a higher positive flow rate of liquid droplets which conservatively maximizes vent pressure losses;

c. The fluid flow in the drywell-to-suppression pool vents is compressible except for the liquid phase; and

d. No heat loss from the gases inside the primary containment is assumed. In reality, condensation of some steam on the drywell surfaces would occur.

6.2.1.1.3.3.1.3 Assumptions for Long-Term Cooling. Following the blowdown period, the ECCS provides water for core flooding, containment spray, and long-term decay heat removal. The containment pressure and temperature response during this period is analyzed using the following assumptions:

a. The low-pressure coolant injection (LPCI) pumps are used to flood the core prior to 600 sec after the accident. The HPCS is assumed available for the entire accident;

b. After 600 sec, the LPCI pump flow may be diverted from the RPV to the containment spray. This is manual operation. Actually, the containment spray need not be activated at all to keep the containment pressure below the containment design pressure. Prior to activation of the containment cooling mode (assumed at 600 sec after the accident) all of the LPCI pump flow will be used to flood the core. In response to indications of significant core damage the operators are directed to initiate containment spray to reduce potential radioactivity released;

c. The effects of decay energy, stored energy, and energy from the metal-water reactor on the suppression pool temperature are considered;

d. The suppression pool is assumed to be the only heat sink available in the containment system;

e. After approximately 600 sec, it is assumed that the RHR heat exchangers commence to remove energy from the containment by means of recirculation cooling from the suppression pool with the SW system; and

f. The performance of the ECCS equipment during the long-term cooling period is evaluated for each of the following three cases of interest:

Case A: Offsite power available - all ECCS equipment and containment spray operating.

Case B: Loss of offsite power, minimum diesel power available for ECCS and containment spray.

Case C: Same as Case B except no containment spray.

Case C is limiting as it results in the highest peak suppression pool temperature and containment pressure. Since power uprate does not change the results of the three cases relative to each other, Case C was reevaluated for power uprate conditions.

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses. Table 6.2-4 provides the initial reactor coolant system and containment conditions used in the accident response evaluation. The tabulation includes parameters for the reactor, the drywell, the suppression chamber, and the vent system. Table 6.2-3 provides the initial conditions and numerical values assumed for the recirculation line break accident as well as the sources of energy considered prior to the postulated pipe rupture. The assumed conditions for the reactor blowdown are also provided. The mass and energy release sources and rates for the containment response analyses are given in Section 6.2.1.3.

6.2.1.1.3.3.1.5 Short-Term Accident Response. The calculated containment pressure and temperature responses for the recirculation line break are shown in Figures 6.2-3 and 6.2-4, respectively.

The suppression chamber is pressurized by the carryover of noncondensables from the drywell and by heatup of the suppression pool. As the vapor formed in the drywell is condensed in the suppression pool, the temperature of the suppression pool water peaks and the suppression chamber pressure stabilizes. The drywell pressure stabilizes at a slightly higher pressure; the

difference being equal to the downcomer submergence. During the RPV depressurization phase, most of the noncondensable gases initially in the drywell are forced into the suppression chamber. However, following the depressurization, noncondensables will redistribute between the drywell and suppression chamber by means of the vacuum breaker system. This redistribution takes place as steam in the drywell is condensed by the relatively cool ECCS water which is beginning to cascade from the break causing the drywell pressure to decrease.

The ECCS supplies sufficient core cooling water to control core heatup and limit metal-water reaction to less than 0.07%. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water (steam flow is negligible) transports the core decay heat out of the RPV, through the broken recirculation line, in the form of hot water which flows into the suppression chamber by means of the drywell-to-suppression chamber vent system. This flow provides a heat sink for the drywell atmosphere and thereby causes the drywell to depressurize.

Table 6.2-5 provides the peak pressure, temperature, and time parameters for the recirculation line break as predicted for the conditions of Table 6.2-4 and corresponds with Figures 6.2-3 and 6.2-4. Figure 6.2-5 shows the time dependent response of the floor (deck) differential pressure.

During the blowdown period of the LOCA, the pressure suppression vent system conducts the flow of the steam-water gas mixture in the drywell to the suppression pool for condensation of the steam. The pressure differential between the drywell and suppression pool controls this flow. Figure 6.2-6 provides the mass flow versus time relationship through the vent system for this accident.

6.2.1.1.3.3.1.6 Long-Term Accident Responses. To assess the adequacy of the containment following the initial blowdown transient an analysis was made of the long-term temperature and pressure response following the accident. The analysis assumptions are those discussed in Section 6.2.1.1.3.3.1.3 for the three cases of interest. The initial pressure response of the containment (the first 600 sec after break) is the same for each case. As can be seen from Figures 6.2-7, 6.2-8, and 6.2-9, Case C is the limiting event.

Case A: All ECCS equipment operating - with containment spray

This case assumes that offsite ac power is available to operate all cooling systems. During the first 600 sec following the pipe break, the HPCS, LPCS, and all LPCI pumps are assumed operating. All flow is injected directly into the reactor vessel.

After 600 sec, both RHR heat exchangers are activated to remove energy from the containment. During this mode of operation the flow from two of the LPCI pumps is routed through the RHR heat exchangers where it is cooled before being discharged into the containment spray header.

The containment pressure response to this set of conditions is shown as Curve A in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as Curve A in Figures 6.2-8 and 6.2-9. After the initial blowdown and subsequent depressurization due to core spray and LPCI core flooding, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment. When the energy removal rate of the RHR system exceeds the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually. Table 6.2-6 summarizes the cooling equipment operation, the peak long term containment pressure following the initial blowdown peak, and the peak suppression pool temperature.

Case B: Loss of offsite power - with delayed containment spray

This case assumes no offsite power is available following the accident and that only the HPCS and one LPCI diesel (Divisions 3 and 2, respectively) are available. For the first 600 sec following the break, one HPCS, and two LPCI pumps are used exclusively for core cooling. After 600 sec, the RHR heat exchanger is activated. The flow from one pump is routed through the heat exchanger and is discharged to the containment spray line. The second LPCI pump is assumed to be shut down. The containment pressure response to this set of conditions is shown as Curve B in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as Curve B in Figures 6.2-8 and 6.2-9. A summary of this case is given in Table 6.2-6.

Case C: Loss of offsite power - no containment spray

This case assumes no offsite power is available following the accident and that only the HPCS and one LPCI diesel (Divisions 3 and 2, respectively) are available. For the first 600 sec following the accident, one HPCS, and two LPCI pumps are used exclusively to cool the core.

After 600 sec, one RHR heat exchanger is activated to remove energy from the containment, but containment spray is not activated. The LPCI flow cooled by the RHR heat exchanger is discharged into the RPV. The second LPCI pump is assumed to be shut down. The containment pressure response to this set of conditions is shown in Figure 6.2-10. The corresponding drywell and suppression pool temperature responses are shown in Figures 6.2-11 and 6.2-12. A summary of this case is given in Table 6.2-6.

When comparing the “spray” Case B with the “no spray” Case C at the same power level, the same RHR heat exchanger duty is obtained since the suppression pool temperature response is approximately the same as shown in Figure 6.2-9. Thus, the same amount of energy is

removed from the pool whether the exit flow from the RHR heat exchanger is injected into the reactor vessel or into the drywell as spray. Although the peak containment pressure is higher for the "no spray" case, the pressure is significantly less than the containment design pressure.

Figure 6.2-13 shows the rate at which the RHR system heat exchanger will remove heat from the suppression pool following a LOCA.

6.2.1.1.3.3.1.7 Chronology of Accident Events. A complete description of the containment response to the design basis recirculation line break has been given in Sections 6.2.1.1.3.3.1.5 and 6.2.1.1.3.3.1.6. Results for this accident are shown in Figures 6.2-3 through 6.2-6, 6.2-10, 6.2-11, 6.2-12, and 6.2-13. A chronological sequence of events for this accident from time zero is provided in Table 6.2-8.

6.2.1.1.3.3.2 Main Steam Line Break. The sequence of events immediately following the rupture of a main steam line between the reactor vessel and the flow limiter have been determined. The flow in both sides of the break will accelerate to the maximum allowed by the critical flow considerations. In the side adjacent to the reactor vessel, the flow will correspond to critical flow in the steam line break area. Blowdown through the other side of the break will occur because the steam lines are all interconnected at a point upstream of the turbine by the bypass header. This interconnection allows primary system fluid to flow from the three unbroken steam lines, through the header and back into the drywell by means of the broken line. Flow will be limited by critical flow in the steam line flow restrictor. The total effective flow area is given in Figure 6.2-14 which is the sum of the steam line cross sectional area and the flow restrictor area. A slower closure rate of the isolation valves in the broken line would result in a slightly longer time before the total valve area of the three unbroken lines equals the flow limiter area in the broken line. The effective break area in this case would start to reduce at 5 sec rather than 4.3 sec as demonstrated in Table 6.2-10. The drywell design temperature (340°F) was determined based on a bounding analysis of the superheated gas temperature. The short-term peak drywell temperature is controlled by the initial steam flow rate during a large steam line break. Since the vessel dome pressure assumed for the original rated analysis (1055 psia) is unchanged by power uprate, the initial break flow rate for this event is not impacted. This event was not reanalyzed for power uprate as there would be no impact on the original rated short-term peak drywell temperature value. The peak drywell pressure occurs before the reduction in effective break area due to MSIV closure and is, therefore, insensitive to a possible slower closure time of the isolation valves in the broken lines. The mass and energy release rates are provided in Section 6.2.1.3.

Immediately following the break, the total steam flow rate leaving the vessel would be approximately 8600 lb/sec, which exceeds the steam generation rate in the core of 4140 lb/sec. This steam flow to steam generation mismatch causes an initial vessel depressurization of the reactor vessel at a rate of approximately 42 psi/sec. Void formation in the reactor vessel water causes a rapid rise in the water level, and it is conservatively assumed that the water level reaches the vessel steam nozzles 1 sec after the break occurs. The water level rise time of

1 sec is the minimum that could occur under any reactor operating condition. From that time on, a two-phase mixture corresponding to the overall average vessel quality would be discharged from the break. The use of the overall average vessel quality results in fluid qualities which are considerably lower than would actually occur. Thus, the drywell peak pressure, which increases with decreasing break flow quality, is maximized. During the first second of the blowdown, the blowdown flow will consist of saturated steam. This steam will enter the containment in a super-heated condition of approximately 330°F.

Figures 6.2-15 and 6.2-16 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steam line break accident for original rated power. The short-term performance is not affected by power uprate. The long-term response is bounded by the recirculation suction line break. Therefore, no steam line break analysis was performed for the power uprate condition.

Figure 6.2-16 shows that the drywell atmosphere temperature approaches 330°F after 1 sec of primary system steam blowdown. At that time, the water level in the vessel will reach the steam line nozzle elevation and the blowdown flow will change to a two-phase mixture. This increased flow causes a more rapid drywell-pressure rise. The peak differential pressure occurs shortly after the vent clearing transient. As the blowdown proceeds, the primary system pressure and fluid inventory will decrease, resulting in a decrease in the vent system and the differential pressure between the drywell and suppression chamber.

Table 6.2-5 presents the peak pressures, peak temperatures, and times of this accident as compared to the recirculation line break.

Approximately 50 sec after the start of the accident, the primary system pressure will have dropped to the drywell pressure and the blowdown will be over. At this time the drywell will contain primarily steam, and the drywell and suppression chamber pressures will stabilize. The pressure difference corresponds to the hydrostatic pressure of vent submergence.

The drywell and suppression pool will remain in this equilibrium condition until the reactor vessel refloods. During this period, the emergency core cooling pumps will be injecting cooling water from the suppression pool into the reactor. This injection of water will eventually flood the reactor vessel to the level of the steam line nozzles and the ECCS flow will spill into the drywell. The water spillage will condense the steam in the drywell and, thus, reduce the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the drywell vacuum breakers will open and noncondensable gases from the suppression chamber will flow back into the drywell until the pressure in the two regions equalize.

6.2.1.1.3.3.3 Hot Standby Accident Analysis. This section is not applicable to BWR-5.

6.2.1.1.3.3.4 Intermediate Size Breaks. The failure of a recirculation line results in the most severe pressure loading on the drywell structure. However, as part of the original containment performance evaluation, the consequences of intermediate breaks were also analyzed. This classification covers those breaks for which the blowdown will result in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.1 ft^2 break below the RPV water level. This break area was chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown. The consequences of an intermediate size break are less severe than from a recirculation line rupture. Because these breaks are not limiting, they were not reanalyzed for power uprate.

Following the 0.1 ft^2 break, the drywell pressure increases at approximately 1 psi/sec. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the vents is negligible and the vents will clear when the drywell-to-suppression chamber differential pressure is equal to the vent submergence hydrostatic pressure.

Figures 6.2-17 and 6.2-18 show the drywell and suppression chamber pressure and temperature response for original rated power conditions at 3323 MWt. The ECCS response is discussed in Section 6.3. Approximately 5 sec after the 0.1 ft^2 break occurs, air, steam, and water will start the flow from the drywell to the suppression pool. The steam will be condensed and the air will enter the suppression chamber free space. The continual purging of drywell air and steam to the suppression chamber will result in a pressurization of both the wetwell and drywell to about 25 and 30 psig, respectively. The containment will continue to gradually increase in pressure due to long-term pool heatup until the vessel is depressurized and reflooded.

The ECCS will be initiated as the result of the 0.1 ft^2 break and will provide emergency cooling of the core. The operation of these systems is such that the reactor will be depressurized in approximately 600 sec. This will terminate the blowdown phase of the transient.

In addition, the suppression pool end of blowdown temperature will be the same as that of the recirculation line break because essentially the same amount of primary system energy is released during the blowdown. After reactor depressurization and reflood, water from the ECCS will begin to flow out the break. This flow will condense the drywell steam and eventually cause the drywell and suppression chamber pressures to equalize in the same manner as following a recirculation line rupture.

The subsequent long-term suppression pool and containment heatup transient that follows is essentially the same as for the recirculation line break.

6.2.1.1.3.3.5 Small Size Breaks.

6.2.1.1.3.3.5.1 Reactor System Blowdown Consideration. This section discusses the containment transient associated with small primary systems blowdowns. The sizes of primary system ruptures in this category are those blowdowns that will not result in reactor depressurization due either to loss of reactor coolant or automatic operation of the ECCS equipment. Following the occurrence of a break of this size, it is assumed that the reactor operators will initiate an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with the blowdown of primary system fluid is one of constant enthalpy. If the primary system break is below the water level, the blowdown flow will consist of reactor water. Blowdown from reactor pressure to the drywell pressure will flash approximately one-third of this water to steam and two-thirds will remain as liquid. Both phases will be at saturation conditions corresponding to the drywell pressure.

If the primary system rupture is located so that the blowdown flow consists of reactor steam only, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because the constant enthalpy depressurization of high pressure, saturated steam will result in superheated conditions inside containment.

A small reactor steam leak (resulting in superheated steam) will impose the most severe temperature conditions on the drywell structures and the safety equipment in the drywell. For larger steam line breaks, the superheat temperature is nearly the same as for small breaks, but the duration of the high temperature condition for the larger break is less. This is because the larger breaks will depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to terminate the small break. Like the main steam line break, the small steam line break is also governed by the dome pressure. The small break response is also governed by the operator actions. Since the vessel dome pressure assumed for the original rated analysis (1055 psia) is unchanged by power uprate the initial break flow rate for this event will be unchanged. Assuming the operator action is the same, the event would be terminated in the same manner as for the original rated power analysis. Thus, the small steam line break was not reanalyzed for power uprate.

6.2.1.1.3.3.5.2 Containment Response. For drywell design consideration, the following sequence of events is assumed to occur. With the reactor and containment operating at the maximum normal conditions, a small break occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell will lead to a high drywell pressure

signal that will scram the reactor and activate the containment isolation system. The drywell pressure will continue to increase at a rate dependent on the size of the steam leak. The pressure increase will lower the water level in the vents until the level reaches the bottom of the vents. At this time, air and steam will start to enter the suppression pool. The steam will be condensed and the air will be carried over to the suppression chamber free space. The air carryover will result in a gradual pressurization of the suppression chamber at a rate dependent upon the size of the steam leak. Once all the drywell air is carried over to the suppression chamber, pressurization of the suppression chamber will cease and the system will reach an equilibrium condition. The drywell will contain only superheated steam and continued blowdown of reactor steam will condense in the suppression pool. The suppression pool temperature will continue to increase until the RHR heat exchanger heat removal rate is greater than the decay heat release rate.

6.2.1.1.3.3.5.3 Recovery Operations. The plant operators will be alerted to the incident by the high drywell pressure signal and the reactor scram. For the purposes of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner while limiting the reactor cool down rate to 100°F/hr. This will result in the reactor primary system being depressurized within 6 hr. At this time, the blowdown flow to the drywell will cease and the superheat condition will be terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than at 100°F/hr, then the drywell superheat condition will be shorter.

6.2.1.1.3.3.5.4 Drywell Design Temperature Consideration. For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the 6-hr cool down period. The corresponding design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum superheat temperature. Drywell design temperature requirements are defined by the most limiting environmental conditions assumed to exist inside primary containment during a design basis accident (see Table 3.11-2). As noted in Table 3.11-2, the design temperature of 340°F is the superheat temperature based on a steam leak with the reactor vessel pressure of 400-500 psi and a design containment pressure of 45 psig.

6.2.1.1.3.4 Accident Analysis Models.

6.2.1.1.3.4.1 Short-Term Pressurization Model. The analytical models, assumptions, and methods used by GE to evaluate the containment response during the reactor blowdown phase of a LOCA are described in References 6.2-1 and 6.2-2.

6.2.1.1.3.4.2 Long-Term Cooling Mode. During the long-term, post-blowdown containment cooling transient, the ECCS flow path is a closed loop and the suppression pool mass will be constant. This closed cooling loop provides subcooled water to the vessel from the suppression pool removing residual decay heat. As a result long-term steaming will not occur. This approach is conservative since removal of energy by steaming would require that more energy

be retained in the vessel, and therefore, not released to the containment to maintain the vessel fluid inventory at saturation temperature. The cooling model loop is shown in Figure 6.2-19. There is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident).

The break flow area is assumed to remain constant as a function of time following decompression of the broken line and/or closure of the MSIV during the first few seconds of the reactor blowdown.

6.2.1.1.3.4.3 Analytical Assumptions. The key assumptions employed in the model are as follows:

a. The drywell and suppression chamber atmosphere are both saturated (100% relative humidity),

b. The drywell atmosphere temperature is equal to the temperature of the coolant spilling from the RPV or to the spray temperature if the sprays are activated,

c. The suppression chamber atmosphere temperature is equal to the suppression pool temperature or to the spray temperature if the sprays are activated, and

d. No credit is taken for heat losses from the primary containment or to the containment internal structure.

6.2.1.1.3.4.4 Energy Balance Consideration. The energy balance in the suppression pool is described in References 6.2-1 and 6.2-2.

6.2.1.1.4 Negative Pressure Design Evaluation

Columbia Generating Station does not have automatic initiation of any drywell spray and controls operation of the sprays through procedural guidance. The design and sizing of the reactor building to wetwell (RB-WW) and wetwell to drywell (WW-DW) vacuum breakers considered inadvertent operation of containment sprays as limiting transients. Although this is conservative for design considerations, inadvertent spraying of the drywell is considered more than one single failure or operator error.

The simultaneous operation of both containment spray loops after large and small-break LOCA could be a limiting transient for the containment negative pressure. However this event is based on more than one single failure or operator error and neglects the consideration for adequate core cooling by using both RHR loops. Using the single-failure criterion and considering the need for adequate core cooling following a large-break LOCA, the containment sprays would not be initiated until later in the event by spraying WW first followed by DW with the worse single failure being a RB-WW vacuum breaker to open. This scenario is nonlimiting with respect to floor uplift or negative pressure.

The limiting transient for negative containment pressurization is a small-break LOCA with a coincident single failure of an RB-WW vacuum breaker. This transient uses both WW and DW sprays of a single RHR loop. WW/DW sprays are initiated when required by the Emergency Operating Procedures. The small break within the drywell forces the noncondensables into the wetwell airspace, leaving a steam atmosphere inside the drywell. Once drywell sprays are initiated, pressure rapidly drops and the RB-WW and WW-DW vacuum breakers open to mitigate the transient.

The analysis performed to determine peak negative pressure after large and small-line-break LOCA made the following conservative assumptions:

a. Maximum spray flow of 8200 gpm (combined drywell and wetwell flow),

b. 100% spray efficiency,

c. 50°F spray temperature,

d. Noncondensable gases are purged into the wetwell as a result of the LOCA,

e. The drywell is full of steam at a pressure above wetwell due to the hydrostatic head from downcomer submergence, and

f. Single failure of RB-WW vacuum breaker.

g. Reactor Power is 3702 MWth.

The initial conditions used in the analysis are provided in Table 6.2-19. A summary of the results is provided in Table 6.2-19a.

Drywell spray is not required to maintain the primary containment below design pressure nor is it required for containment cooling. If, following a small-line-break LOCA, the noncondensable gases are purged into the wetwell airspace, the EOPs would direct the operator to initiate wetwell sprays to control wetwell pressure. If containment pressure continues to increase, drywell sprays will be initiated. The appropriate plant procedures direct the operator to initiate drywell sprays in response to indications of significant fuel failures during a LOCA. For the scenario in which containment sprays are initiated, the limiting single failure (or operator error) would be the failure of a RB-WW vacuum breaker. The results of the analysis indicate that the maximum negative pressure differential will be less than 2.0 psid and within the design values as stated in Section 6.2.1.1.2(c).

Multiple valve failure is not considered or expected. The analysis considers two WW-DW vacuum breakers initially out of service, in addition to the single failure of the RB-WW vacuum breaker, to preclude unnecessary shutdowns due to failure of the testing mechanism or position indication. Failure of the testing mechanism is considered more probable than failure of the vacuum breakers to open. It should also be noted that a single failure of a RB-WW vacuum breaker is more limiting than the single failure of a DW-WW vacuum breaker.

6.2.1.1.5 Suppression Pool Bypass Effects

6.2.1.1.5.1 Protection Against Bypass Paths. The pressure boundary between drywell and suppression chamber including the vent pipes, vent header, and downcomers is fabricated, erected, and inspected by nondestructive examination methods in accordance with the applicable ASME Codes. The design pressure differential for this boundary is 25 psid, which is substantially greater than conditions during a DBA. Actual peak accident differential pressure across this boundary is provided in Table 6.2-5.

Penetrations of this boundary except the vacuum breaker seats and vacuum breaker to downcomer flange are welded. The penetrations can be visually inspected.

Potential bypass leakage paths (such as the purge and vent system) have been considered. Each path has at least two isolation valves in the leakage path during normal system lineup. These valves are leaktight containment isolation valves which are all normally closed.

6.2.1.1.5.2 Reactor Blowdown Conditions and Operator Response. In the unlikely event of a primary system leak in the drywell accompanied by a simultaneous open bypass path between the drywell and suppression chamber, several postulated conditions may occur. For a given primary system break area, the maximum allowable leakage capacity can be determined when the containment pressure reaches the accident pressure at the end of reactor blowdown. The most limiting conditions would occur for those primary system break sizes which do not cause rapid reactor depressurization but rather have long leakage duration. These break sizes which are less than 0.4 ft^2 require operator action to terminate the reactor blowdown if there is a bypass path.

There would also be an increase in drywell pressure which leads to drywell venting to the wetwell by means of the downcomers. Both noncondensables and vapor are vented. If no bypass leakage exists, the maximum suppression chamber pressure would be 28 psig, the pressure resulting from displacing all containment noncondensables into the suppression chamber.

Operator action is required to mitigate the consequences of any bypass leakage. Emergency Operating procedures direct initiation of suppression chamber sprays at a chamber pressure

less than the value analyzed in Section 6.2.1.1.5.4. Drywell sprays are initiated if the chamber pressure limit is exceeded.

Class 1E indication is available in the control room allowing the operator to track chamber pressure. Additionally, a two-division system of alarms is provided to alert the operator if the suppression chamber spray initiation value is reached.

6.2.1.1.5.3 Analytical Assumptions. When calculating the allowable leakage capacities for a spectrum of break sizes, the following assumptions are made:

a. Flow through the postulated leakage path is pure steam. For a given leakage path, if the leakage flow consists of a mixture of liquid and vapor, the total leakage mass flow rate is higher but the steam flow rate is less than for the case of pure steam leakage. Since only the steam entering the suppression chamber free space results in the additional containment pressurization, this is a conservative assumption; and

b. There is no condensation of the leakage flow on either the suppression pool surface or the containment and vent system structures. Since condensation acts to reduce the suppression chamber pressure, this is a conservative assumption. For an actual containment there will be condensation, especially for the larger primary system break where vigorous agitation at the pool surface will occur during blowdown.

6.2.1.1.5.4 Analytical Results. The containment has been analyzed to determine the allowable leakage between the drywell and suppression chamber. Figure 6.2-20 shows the allowable leakage capacity $\left(A/\sqrt{K}\right)$ as a function of primary system break area. The area of the leakage flow path is A, and K is the total geometric loss coefficient associated with the leakage flow path.

Figure 6.2-20 is a composite of two curves. If the break area is greater than approximately 0.4 ft^2, natural reactor depressurization will rapidly terminate the transient. For break areas less than 0.4 ft^2, however, continued reactor blowdown limits the allowable leakage to small values.

Burns and Roe, Inc., confirmed the results of the above analysis by GE in Reference 6.2-7. Further evaluation assigned the maximum allowable leakage capacity at $A/\sqrt{K} = 0.050$ ft^2. Since a typical geometric loss factor would be three or greater, the maximum allowable flow path would be about 0.1 ft^2. This corresponds to a 4-in. line size.

A transient analysis using the CONTEMPT-LT (Reference 6.2-8) computer code was performed. The code was modified to include the mass and energy transfer to the suppression

pool from relief valve discharge. The limiting case was a very small reactor system break which would not automatically result in reactor depressurization. For this limiting case, it was assumed that the response of the plant operators was to initiate the drywell sprays when the suppression chamber pressure exceeds 30 psig, and then to proceed to cool the reactor down in an orderly manner of 100°F/hr cool down rate. Heat sinks considered were items such as major support steel inside containment, the reactor pedestal, the diaphragm floor and support columns, and the steel and concrete of the primary containment. Based on this analysis, the allowable bypass leakage used was 0.050 ft^2. The drywell pressure transient is shown in Figure 6.2-21 along with the corresponding curves of wetwell pressure, wetwell temperature, and suppression pool temperature for the original rated power condition.

The mandated allowable bypass leakage of 0.050 ft^2 is above the Technical Specifications containment bypass leakage limits. Periodic testing is performed to confirm that the containment bypass leakage does not exceed $\left(A/\sqrt{K}\right) = 0.0045$ ft^2. Figure 6.2-22 presents the resulting containment transient of 0.0045 ft^2. The peak containment pressure shown in Figure 6.2-22 is well below the containment design pressure.

An evaluation of this scenario with power uprate indicates that the time available for the operator to manually activate the containment spray is not significantly affected by power uprate. Therefore the effect of power uprate on the steam bypass event is determined to be insignificant.

6.2.1.1.6 Suppression Pool Dynamic Loads

A generic discussion of the suppression pool dynamic loads and asymmetric loading conditions is given in Mark II Dynamic Forcing Function Information Report, Reference 6.2-4. A unique plant assessment of these dynamic loads is made in Reference 6.2-5.

The impact of power uprate on the suppression pool dynamic loads defined in Reference 6.2-5 was evaluated for a power uprate to 102% of 110% of the original rated power (3323 MWt) and considering operation with extended load line limit analysis (ELLLA) and SRV out-of-service plus a setpoint tolerance increase to 3%. This evaluation confirmed that there are sufficient conservatism in the suppression pool dynamic loads defined in Reference 6.2-5.

6.2.1.1.7 Asymmetric Loading Conditions

See Section 6.2.1.1.6.

6.2.1.1.8 Primary Containment Environmental Control

6.2.1.1.8.1 Temperature, Humidity, and Pressure Control During Reactor Operation. The drywell is maintained at its normal operating temperature 135°F maximum average/150°F maximum by the use of three lower containment coolers and two upper containment coolers

mounted in the drywell area. The cooling coils for these units are supplied with water at 95°F, or less, from the reactor building closed cooling water system. There is no air cooling equipment in the wetwell since there is no heat producing equipment and the air space is normally less than 95°F. However, leakage past the seating surfaces of MSRVs may cause the wetwell air space temperature to increase due to heat transfer from the MSRV tailpipes to the wetwell atmosphere. In this case, the wetwell air space can be periodically cooled by spraying with RHR to maintain wetwell air space temperatures at or below 117°F, the limit for equipment qualification.

The unit coolers are sufficient to control the temperature and humidity from all expected heat sources and leaks during normal reactor operation. The containment purge system is not used to control containment temperature or humidity during reactor operation.

To relieve pressure during reactor operation, the operator can establish a flow path from the drywell to the standby gas treatment (SGT) system through the drywell purge exhaust line. After the first 24 hr of venting, and assuming the containment atmosphere does not contain unacceptable levels of radioactivity, venting can be valved to the reactor building exhaust system. By opening the 2-in. bypass valves around the purge exhaust valves rather than the purge exhaust valve, flow can be limited to 170 scfm. This flow is adequate for a drywell atmosphere temperature rise from 70°F to 150°F in 3 hr while maintaining the primary containment at no greater than 0.5 psi above the reactor building pressure. The 2-in. bypass valves would limit the radioactivity released prior to valve closure to a very small amount in the unlikely event a LOCA occurs with the vent path open. If necessary, the wetwell can be vented in a similar way to relieve pressure.

The RB-WW and WW-DW vacuum breakers operate automatically to control containment vacuum.

6.2.1.1.8.2 Primary Containment Purging. The primary containment is provided with a purge system to reduce residual contamination and deinert the containment prior to personnel access. This system is designed to produce a purge rate equivalent to three air changes per hour to the net free volume.

The drywell is purged of nitrogen for the scheduled refueling shutdown period and as required for inspection or maintenance. The maximum drywell purge rate is 10,500 cfm. For the first 24 hr of a drywell purge, or if residual airborne contamination is higher than allowable limits for direct release to the atmosphere, the purge is routed through the SGT system. Purge air is taken from the reactor building ventilation supply duct through two 30-in. normally closed isolation valves into the primary containment. The purged nitrogen is extracted from the drywell through two 30-in. normally closed isolation valves and is routed to one of two systems. The discharge can be routed through a normally closed isolation valve to the reactor building exhaust air plenum or to the SGT system. If a high airborne activity occurs,

the radiation monitors at the exhaust air plenum would cause the reactor building ventilation and primary containment purge systems to isolate.

Provision is also made to purge the nitrogen from the suppression chamber section of the primary containment. Purge air is taken from the reactor building supply duct through two 24-in. normally closed isolation valves into the suppression chamber. The nitrogen is extracted from the suppression chamber through two 24-in. normally closed isolation valves and routed to the exhaust air plenum or SGT system in the same manner as the drywell purge exhaust.

The systems are designed to purge either the drywell or the suppression chamber or the two chambers in series or in parallel. To protect the pressure suppression function of the suppression pool, only one vent line and one purge line will be open at any one time during reactor operation.

Purge system operation during reactor operation including startup, hot standby, and hot shutdown will be limited to inerting (through the purge system), deinerting, and pressure control. The containment purge system will not be used for temperature or humidity control during reactor operation.

All containment purge valves, including the 2-in. bypass valves, are designed to shut within 4 sec of receipt of a containment isolation signal and to shut against full containment design pressure. The containment isolation signals and the purge valves are part of the containment isolation system which is an ESF system. Each purge line has two isolation valves. These valves are opened by allowing compressed air to oppose a spring in the valve actuator. The valve is shut on a loss of compressed air, loss of electrical signal, or on a containment isolation signal. If the purge system is operating at the time of a LOCA, the system will automatically be secured. The level of the activity released through the purge system before isolation would be limited to the activity present in the coolant prior to the accident since the purge system will be isolated before any postulated fuel failure could occur. Dual isolation valves are also provided on the nitrogen inerting makeup piping connecting to the purge piping downstream of the 30-in. and 24-in. isolation valves. The nitrogen inerting system permits up to 75 cfh of nitrogen to be added to the containment during reactor operation to compensate for the postulated leakage listed in Table 6.2-1.

The 2-in. bypass valves, used for pressure control during operations, are located in parallel with each purge system exhaust valve. These 2-in. 150# globe valves meet the design requirements of the containment isolation system. They are designed to the same pressure/temperature ratings of the containment and purge valves and are designed to close within 4 sec against the containment design pressure. All four bypass valves can be remotely operated from the control room; are designed to close on F, A, and Z isolation signals; and are operationally qualified against applicable seismic and hydrodynamic loads.

6.2.1.1.8.3 Post-LOCA. The unit coolers are not required after a LOCA since heat removal is then accomplished by the containment cooling system, a subsystem of the RHR system. The Emergency Operating Procedures stipulate that nitrogen inerting is used as long as nitrogen is available. The operation of purge and vent transitions from oxygen control to hydrogen control upon loss of the ability to continue to inert with oxygen levels increasing. The containment purge system has the capability for a controlled purge of the containment atmosphere to aid in atmospheric control, if necessary, in accordance with the guidance provided in the Emergency Operating Procedures.

Any equipment located inside the primary containment which is required to operate subsequent to a LOCA has been designed to operate in the worst anticipated accident environment for the required period of time.

6.2.1.1.9 Postaccident Monitoring

A description of the postaccident monitoring systems is provided in Section 7.5.

6.2.1.2 Containment Subcompartments

The subcompartments in the primary containment analyzed to determine the effects of subcompartment pressurization are the annulus between the sacrificial shield wall and vessel annulus pressurization and the drywell head. For the power uprate and MELLLA evaluation, the limiting breaks in these two regions were analyzed considering reactor operation throughout the power flow map with power uprate, including final feedwater temperature reduction and single loop operation.

Peak subcompartment pressures occur very quickly (during the first few seconds) during the limiting subcompartment pressurization events. Therefore, the pressurization is controlled by the initial break flow rates which are governed by the break size and location and the initial reactor thermal-hydraulic conditions, such as reactor pressure and enthalpy. The limiting operating condition with power uprate with respect to subcompartment pressurization was determined to occur at 3702 MWt, 102% of design power limit 3629 MWt; therefore, the controlling parameters with power uprate were compared to the original values at this condition. The comparison shows that there are negligible differences between the controlling parameters for the original conditions used as the basis for the annulus pressurization and drywell head pressurization analyses and the corresponding parameters with power uprate and MELLLA (Reference 6.2-32 and 3.6-24). Therefore, the basis for the subcompartment pressurization loads is not affected by power uprate.

	Original Conditions (at 3463 MWt)	Power Uprate Conditions (at 3702 MWt)
Vessel dome pressure (psia)	1055	1055
Core inlet enthalpy (Btu/lbm)	532	532
Recirculation line break critical mass flux (lbm/ft^2-sec)	8900	8900
Feedwater enthalpy (Btu/lbm)	403	406
Feedwater line break critical mass flux (lbm/ft^2-sec)	19,300	19,200

The two areas within the primary containment considered to be subcompartments are the area within the sacrificial shield wall and the area above the refueling bulkhead plate at el. 583 ft.

Potential pipe breaks within the sacrificial shield wall have been evaluated. The information is contained in References 3.8-5, 3.8-6, 3.8-7, and 3.8-23.

Two analyses were performed based on original rated power (3323 MWt) to ensure the adequacy of the refueling bulkhead and inner refueling bellows at el. 583 ft. The first analysis, a break of the RCIC head spray line, determines the maximum downward loading due to pipe breaks. The second analysis, a break of the RRC suction line, determines the maximum upward loading.

Subcompartment analyses for a postulated high-energy pipe break in the primary containment were performed for the annulus inside the sacrificial shield wall, and the regions above and below the bulkhead plate which divides the drywell into the upper head region and the lower region.

The analyses for the annulus were reported in References 6.2-9 through 6.2-11 and 6.2-42. The result of the case of a 60-node model of the shield wall annulus for pressure transient calculation was confirmed by the NRC, and the analysis was considered acceptable for the shield wall base design and the design of the shield wall above the base, as stated in NRC letters (References 6.2-12 and 6.2-13). For the MELLLA evaluation a 400-node model of the shield wall was analyzed and the results were bounded by the original 60-node model. (Reference 3.6-24).

Peak and transient loading used to establish the adequacy of the sacrificial shield wall, including the time/space dependent forcing functions, are presented in References 6.2-9 through 6.2-11 and 6.2-34.

These loads were used to produce response spectra for use in evaluating secondary effects such as the dynamic effects on piping systems, equipment, and components attached to the sacrificial shield wall of the RPV. The following changes were made in the original assumptions used in the sacrificial shield wall analysis:

a. The volume in the annulus was utilized to receive the blowdown, with the RPV installation volume conservatively assumed not to be available;

b. A finite time-dependent blowdown was used for the recirculation break utilizing NSSS supplier methodology (Reference 6.2-22). The effect of subcooling was taken into account; and

c. The feedwater pressurization analysis was developed utilizing blowdown values developed by computer analysis.

Annulus pressurization calculations are briefly summarized as follows:

a. Annular volume

The annular volume excluded RPV insulation volume which is conservatively assumed not to be available. This approach is conservative and more realistic than other analyses where only the annular volume on one side of the RPV insulation was available;

b. Finite time dependent blowdown

The blowdown loading values in Reference 6.2-11 were derived with the assumption that the pipe break would occur instantaneously and that the annulus area would see the maximum blowdown at the same time. In actuality, the full flow from the severed pipe ends separate at a distance equal to one-half the pipe diameter. Movement occurs in a finite time and is a function of the stiffness characteristics of the pipe and the restraining capability of the pipe whip restraints.

Displacement versus time data for a finite break opening was developed and a GE analytical method was used for determining the short-term mass and energy release (Reference 6.2-22). The analysis was used for the recirculation loop break but not for the feedwater line since it was determined that the small percentage reduction for the feedwater would not warrant the additional calculations; and

c. Feedwater break blowdown data

The blowdown analysis for the postulated feedwater line break was based on a comprehensive model developed for the entire feedwater system from the condenser to the reactor vessel. This model, in conjunction with the RELAP4/MOD5 computer program (Reference 6.2-14), was used to calculate the transient and energy blowdown data.

Information pertaining to the analyses for the upper head and lower regions is as follows:

a. For the subcompartment analysis in the upper head region, the worst case is a double-ended guillotine break in the 6-in. RCIC line above the RPV head at approximately el. 595 ft. For the analysis in the lower region, the worst case is a double-ended guillotine break in the 24-in. recirculation line anywhere inside the drywell. The pipe breaks were postulated for the subcompartment structural and component support designs;

b. The blowdown mass and energy release rates as functions of time for the 6-in. RCIC line break are shown in Tables 6.2-20 and 6.2-21. The blowdown mass and energy release rates as functions of time for the 24-in. recirculation line break are shown in Tables 6.2-22 and 6.2-23;

c. The subcompartment analyses for the case of a 6-in. RCIC line break in the upper head region and the case of a 24-in. recirculation line break were performed with the Computer Code RELAP4/MOD5 (Reference 6.2-14).

   Figure 6.2-23 shows the nodalization scheme in the drywell. Figure 6.2-24 depicts the plane view of vents in the bulkhead plate and shows the sectional views and dimensions of the bulkhead vents;

d. The nodal volume data used for the analysis of a 6-in. RCIC line break in the upper head region and the analysis of a 24-in. recirculation line break in the lower region is shown in Table 6.2-24. Table 6.2-25 shows the flow path data for the analysis of a 6-in. RCIC line break and Table 6.2-26 shows the flow path data for the analysis of a 24-in. recirculation line break;

e. Since there are no significant obstructions in the proximity of the pipe break considered in the analysis, significant pressure variation in any direction is not expected. The two-node model used for the analyses is considered to be adequate and a sensitivity study is not necessary;

f. There are no movable obstructions in the vicinity of the vents. Insulation for piping and components was assumed to remain intact during the accident, and volume of insulation was subtracted from the nodal volumes;

g. The absolute pressure responses as a function of time in the upper head region and the lower region in the drywell are shown in Figure 6.2-25 for the case of a 6-in. RCIC line break and in Figure 6.2-26 for the case of a 24-in. recirculation line break. Figures 6.2-27 and 6.2-28 represent the pressure differential across the bulkhead plate for the cases of a 6-in. RCIC line break and a 24-in. recirculation line break;

h. The peak differential pressure and the time of the peak for the cases of a 6-in. RCIC line break and a 24-in. recirculation line break are shown in Table 6.2-27; and

i. Peak and transient loading used to establish the adequacy of the sacrificial shield wall, including the time/space-dependent forcing functions are contained in References 6.2-9 through 6.2-11 and 3.8-23.

   Peak and transient loading in other major compartments such as the drywell and the upper head region of primary containment were included in the basic design. Since these compartments are large and relatively unencumbered, the loads are time-dependent but relatively uniform throughout. The time-dependent loads were applied as equivalent static loads, utilizing the appropriate dynamic loads factors. Following a LOCA, the refueling bulkhead would require requalification prior to use. This is acceptable because the refueling bulkhead does not perform a safety-related function and would not become a missile during the postulated LOCA.

   The analyses for the annulus are contained in References 6.2-9 through 6.2-11. Evaluation of potential pipe breaks within the sacrificial shield wall are in Reference 3.8-5, 3.8-6, 3.8-7, and 3.8-23.

6.2.1.3 <u>Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents</u>

Where the ECCS enter into the determination of energy released to the containment, the single failure criterion has been applied to maximize the energy release to the containment following a LOCA.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-9 provides the mass and enthalpy release data for the recirculation line break. Blowdown flow rates do not change significantly during the 24-hr period following the

accident. Figures 6.2-29 and 6.2-30 show the blowdown flow rates for the recirculation line break. This data was employed in the DBA containment pressure-temperature transient analyses.

Table 6.2-10 provides the mass and enthalpy release data for the main steam line break. Blowdown flow rates do not change significantly during the 24-hr period following the accident. Figure 6.2-31 shows the vessel blowdown flow rates for the main steam line break as a function of time after the postulated rupture. This information has been employed in the containment response analyses.

6.2.1.3.2 Energy Sources

The reactor coolant system conditions prior to the line break are presented in Tables 6.2-3 and 6.2-4. Reactor blowdown calculations for containment response analyses are based on those conditions during a LOCA.

The energy released to the containment during a LOCA is comprised of the following:

a. Stored energy in the reactor system,
b. Energy generated by fission product decay,
c. Energy from fuel relaxation,
d. Sensible energy stored in the reactor structures,
e. Energy being added by the ECCS pumps, and
f. Metal-water reaction energy.

All but the pump heat energy addition is discussed or referenced in this section. The pump heat rate was used in evaluating the containment response to the LOCA and is conservatively selected as a constant input of 4890 Btu/sec to the system. The pump heat rate is added to the decay heat rate for inclusion in the analysis.

Following each postulated accident event, the stored energy in the reactor system and the energy generated by fission product decay will be released. The rate of release of core decay heat for the evaluation of the containment response to a LOCA is provided in Table 6.2-11 as a function of time after accident initiation.

Following a LOCA, the sensible energy stored in the reactor primary system metal will be transferred to the recirculating ECCS water and will, thus, contribute to the suppression pool and containment heatup.

6.2.1.3.3 Reactor Blowdown and Core Reflood Model Description

The reactor primary system blowdown flow and core reflood rates were evaluated with the model described in References 6.2-1 and 6.2-2.

6.2.1.3.4 Effects of Metal-Water Reaction

The containment systems are designed to accommodate the effects of metal-water reactions and other chemical reactions which may occur following a LOCA. The amount of metal-water reaction which can be accommodated is consistent with the performance objectives of the ECCS. Section 6.2.5 provides a discussion on the generation of metal-water hydrogen within the containment.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment has been provided within Section 6.2.1.1.3.3.

6.2.1.3.6 Long Term Cooling Model Description

The long term cooling model is described in Section 6.2.1.1.3.4.

6.2.1.3.7 Single Failure Analysis

Containment analysis results assuming the worst single active failure are presented in Section 6.2.1.

6.2.1.4 Not applicable to BWR plants.

6.2.1.5 Not applicable to BWR plants.

6.2.1.6 Testing and Inspection

6.2.1.6.1 Structural Integrity Test

The test for structural integrity is discussed in Section 3.8.

6.2.1.6.2 Integrated Leak Rate Test

Leak rate tests are conducted to verify that leakage out of the primary containment does not exceed 0.375% per day at 38 psig. This test is discussed in Section 6.2.6.

6.2.1.6.3 Drywell Bypass Leak Test

Tests are conducted, in accordance with the Technical Specifications, to verify that the drywell-wetwell bypass leakage does not exceed an equivalent leakage of $A/\sqrt{K}$ equal to 0.0045 ft^2. This is less than the bypass leakage allowed.

6.2.1.6.4 Vacuum Relief Testing

Tests are conducted in accordance with the Technical Specifications to verify the proper operation of the vacuum relief valves.

6.2.1.7 Required Instrumentation

The instrumentation required to monitor containment parameters and to initiate safety functions is discussed in Chapter 7.

6.2.2 RESIDUAL HEAT REMOVAL CONTAINMENT HEAT REMOVAL SYSTEM

6.2.2.1 Design Bases

The RHR containment heat removal function is accomplished by the use of an operational mode of the RHR system. The purpose of this system is to prevent excessive containment temperatures and pressures, thus maintaining containment integrity following a LOCA. To fulfill this purpose, the RHR containment cooling system meets the following safety design bases:

a. The system will limit the long term bulk temperature of the suppression pool to ≤204.5°F when considering the energy additions to the containment following a LOCA. These energy additions, as a function of time, are provided in Section 6.2.1;

b. The single failure criterion applies to the system;

c. The system is designed to safety grade requirements including the capability to perform its function following an SSE;

d. The system will remain operational during those environmental conditions imposed by a LOCA;

e. Each active component of the system is testable during normal operation of the nuclear power plant;

f. Minimum net positive suction head (NPSH) is maintained on the RHR pumps even with the containment at atmospheric pressure, the suppression pool at a maximum temperature, and postaccident debris entrained on the beds of the suction strainers; and

g. Withstands dynamic effect of pipe breaks inside and outside of containment (see Section 3.6).

The primary containment unit coolers provide for containment heat removal during nonaccident conditions. These coolers are not an ESF and no credit is taken for them during accident events.

6.2.2.2 Residual Heat Removal Containment Cooling System Design

The RHR containment cooling system is an integral part of the RHR system. Water is drawn from the suppression pool, pumped through one or both RHR heat exchangers and delivered to the vessel, the suppression pool, the drywell spray header, or the suppression pool vapor space spray header.

Water from the SW system is pumped through the heat exchanger tube side to remove heat from the process water. Two cooling loops are provided, each mechanically and electrically separate from the other to achieve redundancy. The process diagram including the process data from all design operating modes and conditions is provided in Section 5.4.

All portions of the RHR containment cooling system are designed to withstand operating loads and loads resulting from natural phenomena.

Construction codes and standards are covered in Section 3.2. Seismic and environmental qualifications are discussed in Section 3.10 and 3.11, respectively.

There are no signals which automatically initiate containment cooling; however, the SW system is automatically initiated by the same signals which start up the ECCS. The capacity of power sources, including the standby diesels, is sufficient to allow operation of the SW pumps simultaneously with the ECCS pumps. An ECCS pump need not be secured prior to starting RHR containment cooling.

To start RHR containment cooling after a LOCA resulting from a large break, the operator needs only to verify that the normally open RHR heat exchanger isolation valves are open and then shut the heat exchanger bypass valve. The rated containment cooling flow, 7450 gpm, can be achieved through the LPCI line, the drywell spray line, or through the test line and wetwell spray line, which directs the heat exchanger discharge directly into the suppression pool. Thus, the design allows containment cooling simultaneously with core flooding or containment spray. If the break size is small enough to limit reactor depressurization, the rated containment cooling flow cannot be established through the LPCI line. The operator must then direct the RHR containment cooling flow through the drywell spray line or through the test line; however, the operator must not divert LPCI flow away from the reactor until adequate core cooling is ensured. In addition, an electrical interlock prevents actuation of a drywell spray loop until the corresponding LPCI injection valve has been shut. A second electrical

interlock prevents actuation of drywell spray if there is no high drywell pressure signal present.

When allowed, the operator may start drywell spray by shutting the LPCI injection valve and then opening the drywell spray valves. Similarly, the operator may divert the flow directly to the suppression pool by shutting the LPCI injection valve and then opening the test line valve.

Preoperational tests were performed to verify individual component operation, individual logic element operation, and system operation up to the drywell spray spargers. A sample of the sparger nozzles were bench tested for flow rate versus pressure drop to evaluate the original hydraulic calculations. The spargers were tested by air and visually inspected to verify that all nozzles were clear.

6.2.2.3 Design Evaluation of the Containment Cooling System

The containment spray system is discussed in Section 5.4.7. Containment spray is not required for heat removal.

In the event of the postulated design basis LOCA, the short-term energy release from the reactor primary system will be dumped to the suppression pool. This will cause a pool temperature rise of approximately 56°F in the short term. Subsequent to the accident, fission product decay heat will result in a continuing energy input to the pool. The RHR containment cooling system will remove this energy which is input to the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

To evaluate the adequacy of the containment cooling system, the following sequence of events is assumed to occur.

a. With the reactor initially at the reactor power level specified in Table 6.2-4, a LOCA occurs;

b. A loss of offsite power occurs and either Division 1 or 2 diesel fails to start and remains out of service during the entire transient. This is the worst single failure;

c. Only three ECCS pumps are activated and operated as a result of there being no offsite power and minimum onsite power; and

d. After 10 minutes it is assumed that the plant operators shut the bypass valve on one RHR heat exchanger to start containment heat removal. Once containment cooling has been established, no further operator actions are required.

Each RHR pump suppression pool suction consists of a pipe "T" with a suction strainer at each end. During normal operation, some fiber and corrosion products have accumulated on the strainers. This accumulation is considered in the design of the strainers, which will entrain additional debris following a LOCA. The potential for the additional accumulation of debris during a LOCA is discussed in Section 6.2.1. Wetwell strainers are periodically cleaned to ensure that post-LOCA accumulation of debris on the strainer beds is within acceptable limits.

The relative locations of the RHR suction and return lines in the suppression pool are shown in Figure 6.2-32. Mixing in the pool is primarily accomplished by the vertical and horizontal displacement between the suction and discharge line for a loop. The structures in the suppression pool act as baffles and improve mixing. Vertical thermal stratification in the suppression pool is prevented by locating the discharge lines above the suction lines.

Required operator actions are minimal. Even without operator action, some heat removal will occur from the suppression pool to the spray ponds. The ECCS initiation signals start up both SW and LPCI flow. The LPCI flow is primarily through the RHR heat exchanger bypass line since the bypass valve is signaled to open. Since the heat exchanger isolation valves are normally open, some of the LPCI flow (approximately 40%) will flow through the heat exchanger. It is estimated that for break sizes resulting in RPV depressurization and rated LPCI flow, the heat exchangers' duty with the partial shell side flow (i.e., no operator action) will be approximately 75% of the heat exchangers' duty with full shell side flow. Thus it is estimated that operator delays after a large break would result in only a moderate increase in suppression pool temperatures.

<u>Summary of Containment Cooling Analysis</u>

When calculating the long-term, post-LOCA pool temperature transient, it is assumed that the initial suppression pool temperature is at its maximum value and that the SW temperature is as described in Table 6.2-4 throughout the accident period. These assumptions conservatively bound the heat sink temperature to which the containment heat is rejected. In addition, the RHR heat exchanger is assumed to be in a fully fouled condition at the time the accident occurs. This conservatively minimizes the heat exchanger heat removal capacity. The resultant suppression pool temperature transient is described in Section 6.2.1 and is shown in Figure 6.2-12. Even with the degraded conditions outlined above, the maximum uprate temperature is 204.5°F, which is less than the original 220°F. The results of the containment analysis performed to evaluate reduced ECCS flow rates (RHR/LPCI and LPCS) are bounded by the power uprate analysis.

When evaluating this long-term suppression pool transient, all heat sources in the containment are considered with no credit taken for any heat losses other than through the RHR heat exchanger. These heat sources are discussed in Section 6.2.1. Figure 6.2-13 shows the actual heat removal rate of the RHR heat exchanger.

GE SC 06-01 addresses the unlikely event of an inoperable RHR heat exchanger with all ECCS pumps running post-accident. This event was evaluated in Reference 6.2-42 and found that if all four low pressure pumps (LPCS, 3-LPCI) were injecting post-accident the suppression pool bounding temperature may be exceeded. The timing for this action is detailed in Reference 6.2-42. In the event of an inoperable RHR heat exchanger, operating procedures ensure that the three low pressure pumps not providing operational heat exchanger flow will be secured before suppression pool temperature limits are exceeded.

It can be concluded that the conservative evaluation demonstrates that the RHR system in the suppression pool cooling mode limits the post-DBA containment temperature transient.

6.2.2.4 Tests and Inspections

The preoperational test program of the containment cooling system is described in Sections 14.2.12 and 5.4.7. Operational testing is in accordance with the Technical Specifications.

6.2.2.5 Instrumentation Requirements

The details of the instrumentation are provided in Chapter 7. The containment cooling mode of the RHR system is manually initiated from the control room.

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The secondary containment system includes the secondary containment structure and the safety-related systems provided to control the ventilation and cleanup of potentially contaminated volumes of the secondary containment structure following a DBA. This section discusses the secondary containment design. The SGT system is used to depressurize and clean the secondary containment atmosphere and is discussed in Section 6.5.1.

The secondary containment structure is synonymous with the reactor building. Sufficient openings exist among all areas of the reactor building to ensure that no significant long-term pressure gradients can exist within the secondary containment. In addition, with the exception of the steam tunnel, there are sufficient vent areas in all confined or enclosed spaces such that pressure can be safely relieved into the rest of secondary containment for all postulated pipe breaks within those spaces.

The steam tunnel runs through the reactor building and into the turbine generator building. The portion of the steam tunnel within the reactor building is physically and functionally part of the secondary containment during normal operation, expected transients, and all postulated accident events except for a pipe break within the steam tunnel. The steam tunnel relieves pressure through blowout panels which normally separate the turbine generator and reactor building portions of the steam tunnel.

6.2.3.1 Design Bases

The secondary containment structure completely encloses the primary containment. The secondary containment provides an additional barrier to fission product release when primary containment is operable and provides the primary barrier during operations with the potential to drain the reactor vessel (OPDRV).

The secondary containment structure, in conjunction with other secondary containment systems, provides the means of controlling and minimizing leakage from the primary containment to the outside atmosphere during a LOCA.

The reactor building pressure control system operates together with the reactor building ventilation system during normal operation to maintain building pressure greater than or equal to 0.25 in. of vacuum water gauge as indicated at the reactor building el. 572 ft. During emergency operation the pressure control system operates together with the SGT system to maintain a vacuum in secondary containment at greater than or equal to 0.25 in. vacuum water gauge on all building surfaces. This ensures that leakage is into the secondary containment during normal and emergency operation. Thus, all the reactor building air is either exhausted through the exhaust air plenum, where it is constantly monitored, or discharged through the filtration units of SGT system. The reactor building pressure control system and the reactor building ventilation system are described in Section 9.4.

The secondary containment isolation signals, secondary containment isolation valves, isolation valves for the reactor building ventilation system, SGT system, and reactor building pressure control system are all designed to Seismic Category I, Class 1E requirements. The design bases loads for the SGT system are given in Section 6.5.1. These systems can be periodically inspected and functionally tested.

The secondary containment structure houses the refueling and reactor servicing equipment, the new and spent fuel storage facilities, and other reactor auxiliary or service equipment, including all or part of the reactor core isolation cooling system, reactor water cleanup demineralizer system, standby liquid control system, control rod drive (CRD) system equipment, the ECCS, SGT system, and electrical equipment components. The secondary containment structure protects the equipment from Seismic Category I disturbances, the design basis tornado and tornado-generated missiles, and the design basis wind. The secondary containment structure is designed to meet the following design bases:

a. The reactor building is designed to meet Seismic Category I requirements;

b. The reactor building is designed and constructed in accordance with the structural design criteria presented in Section 3.8, and provides for low inleakage and outleakage during reactor operation. The building is designed to limit the inleakage rate to 100% of the reactor building free volume per day when maintained at a negative building pressure of 0.25 in. of water;

c. The reactor building is designed to withstand applied wind pressures resulting from the design basis wind velocity, including gusts of 100 mph at an elevation of 30 ft above grade. The pressure of the design basis wind velocity on the reactor building is discussed in Section 3.3;

d. The reactor building is designed to withstand pipe whip loads plus jet impingement of jet reaction loads due to high-energy pipe breaks outside primary containment;

e. The reactor building design allows for periodic inspections and functional tests of the penetrations, ventilation system (including automatic isolation), pressure control system, and SGT system;

f. The reactor building is designed to withstand applied wind pressures resulting from the design basis tornado. The effects of the design basis tornado pressures on the structure are discussed in Section 3.3 and tornado-generated missiles are discussed in Section 3.5; and

g. The reactor building is designed for all probable combinations of the design basis wind and the design basis tornado velocities and associated differences of pressure within the structure and atmospheric pressure outside the structure.

6.2.3.2 System Design

See Figures 1.2-7 through 1.2-12 for general arrangement drawings of the reactor building. Also see Figures 3.8-1 and 3.8-2. See Table 6.2-12 for the design and performance data for the secondary containment structure.

The major design provisions that prevent primary containment leakage from bypassing the SGT system, except for those lines identified as potential bypass leakage paths in Table 6.2-16, are the reactor building pressure control system, the reactor building ventilation isolation system, the isolation signals, and the standby power system.

Normal reactor building ventilation system is not required to operate during accident conditions. The system is automatically shut down and the SGT system started in the event of any of the following isolation signals:

a. Reactor vessel low-low water level,
b. High drywell pressure, and
c. High radiation level in the reactor building exhaust air plenum.

All ventilation system penetrations of secondary containment (except those of the SGT system) are fitted with two fail-closed, air-operated butterfly dampers in series. All dampers automatically close on any one of the isolation signals.

Penetrations of the secondary containment associated with the SGT system are fitted with two motor operated butterfly valves in series. The motor operated valves, which are powered

from the essential power buses, are opened automatically, and the SGT system is started by any of the signals which isolate the secondary containment.

Penetrations of the reactor building are designed with leakage characteristics consistent with leakage requirements of the entire building. Entrance to the reactor building is through interlocking double door personnel air locks. Entrance to the reactor building vehicle air lock (railroad bay) is through an interlocking air lock system.

The storage/receiving area for casks is the vehicle air lock (railroad bay). The vehicle air lock (railroad bay) is completely within and along the south side of the reactor building at el. 441 ft. One of the interlocked doors is the exterior vehicle door at the east end of the vehicle air lock, and the other interlocked door is the interior person door at the west end of the vehicle air lock. There are also two hatches that are interlocked with the vehicle air lock entrance doors.

All entrances to the reactor building are through interlocking double door air lock systems and, therefore, building ingress and egress do not jeopardize the integrity of the secondary containment. All openings such as personnel doors leading into the secondary containment are under administrative control and are provided with position indication and alarm in the main control room if they are not closed after the time allowed for ingress/egress. An exception is an access hatch which has been provided in one of the steam tunnel blowout panels. When not in use, the hatch is secured closed by security bolts and padlocks. Another exception is the CRD rebuild room drop chute which is used to dispose of contaminated CRD components. The drop chute penetrates the reactor building floor at el. 471 ft and becomes a part of secondary containment when the vehicle air lock (railroad bay) exterior doors are open. A valve at el. 501 ft allows CRD components (e.g., filters) to be dropped down the chute without breaching secondary containment.

The reactor building pressure control system is designed to eliminate fluctuations in reactor building pressure by such factors as wind gusts. Reactor building pressure is indicated and recorded in the main control room and loss of negative pressure is alarmed.

The reactor building pressure control system automatically maintains a subatmospheric pressure in the reactor building by monitoring the differential pressure between the reactor building interior and the external atmosphere. The differential pressure is monitored by eight differential pressure transmitters, four in each division, which measure the differential pressure between the internal reactor building and each of the four external sides of the reactor building. The signal which indicates the least differential pressure controls the position of the blades in the normal reactor building exhaust fan units. In the event of reactor building isolation, the reactor building pressure control system controls reactor building pressure by SGT system fan flow.

Piping that connects to primary containment and passes through secondary containment is not considered a potential secondary containment bypass leak path if isolated by blind flanges or a rupture disc.

Condensate from the condensate storage tanks can be used to flush ECCS and RHR shutdown cooling lines. Blind flanges are installed in the condensate system at spool piece COND-RSP-4 and in the RHR system downstream of RHR-V-108 and RHR-V-109 and at spool piece RHR-RSP-1 to isolate potential secondary containment bypass leak paths. The spool pieces are installed to comply with the piping support analyses. The spool pieces COND-RSP-1, COND-RSP-2, COND-RSP-3, COND-RSP-5, and COND-RSP-6 are connected to the condensate piping with blind flanges at the other end. If connected to the corresponding RHR lines, blind flanges would be necessary to isolate potential secondary containment bypass leak paths.

Table 6.2-16 presents a tabulation of primary containment process piping penetrations. The lines that penetrate both the primary and secondary containment were evaluated for potential bypass leakage paths as summarized in Table 6.2-16. The guidance of the NRC Branch Technical Position Containment Systems Branch (BTP CSB) 6-3 (Reference 6.2-40) were addressed in considering potential bypass leakage paths. Designs provided to prevent through-line leakage are dependent on whether the working fluid in the associated system is gaseous or liquid. Lines that vent (gaseous release) into the reactor building, will be treated by the SGT system. Lines that penetrate primary and secondary containment that normally contain water provide a water seal between the primary containment and the environment upon the primary isolation valve closure. If a break were to occur in the lines, the water or gas would evacuate into the reactor building, and any leakage through the failed line would be collected by the floor drain system or processed by the SGT system. Some lines that penetrate both the primary and secondary containment are seismically qualified outside of the secondary containment. These lines are considered closed systems and are not categorized as potential bypass paths. Lines that penetrate the primary and secondary containment are contained in one or more of the categories listed below.

a. Operate post-LOCA at pressure higher than the primary containment pressure or are seismically qualified.

b. Are vented to the secondary containment.

c. Are provided with water seal assessed against primary containment valve leakage characteristics.

Therefore, the primary containment isolation valve leak rate tests and SGT system operability tests are adequate to ensure that bypass leakage will not occur and separate leakage testing of the secondary containment isolation valves is not required. An additional conservative assumption of secondary containment bypass leakage of 0.04% volume per day, the secondary containment bypass limit, for the first 24 hr and 0.02% volume per day after 24 hr was included in dose consequence analyses in Chapter 15. The analyses demonstrated that the potential bypass leakage contribution from water lines to the dose consequences were negligible.

The design and construction codes, standards, and guides applied to the buildings and SSCs are discussed in Chapter 3.

6.2.3.3 Design Evaluation

The SGT system will maintain the secondary containment at a negative pressure with respect to the external environment following the design basis loss-of-coolant accident. The design flow rate of the exhaust system is based on the following criteria:

a. The rate of in-leakage assumption in based on the 100% of the secondary containment volume per day.

b. The exhaust flow rate is based on maintaining containment vacuum greater than or equal to 0.25 in. of vacuum water gauge.

The SGT system is described in Section 6.5.

6.2.3.3.1 Calculation Model

The parametric analysis of secondary containment responses following a LOCA were performed using the general purpose thermal-hydraulic computer program GOTHIC (Reference 6.2-39). The GOTHIC program solves conservation of mass, momentum, and energy equations for multi-component, multi-phase flows. The phase balance equations are coupled by mechanistic models for interface mass, momentum, and energy transfers that cover the entire flow regime as well as single-phase flows. Aspects of the reactor building taken into consideration for the model include:

a. Heat loads modeled in the respective rooms (multiple volumes),
b. Heat transfer for primary to secondary containment (negligible),
c. Heat transfer between secondary containment and the outside environment,
d. Heat transfer between rooms and reactor building floors (multiple elevations),
e. Room cooler efficiency, and
f. Secondary containment relative humidity.

6.2.3.3.2 Results

A series of parametric studies were performed to evaluate varying meteorological conditions and heat loads on the drawdown analyses. Representative temperature and pressure response curves are provided as Figures 6.2-34 and 6.2-35. These analyses are based on the following:

	PARAMETER	VALUE
a)	The reactor building was modeled using lumped parameter volumes totaling	Approximately 3,500,000 ft^3
b)	Exhaust rate during drawdown	4800 cfm
c)	Secondary containment in leakage rate	2430 cfm
d)	Initial reactor building temperature range	50°F to 75°F
e)	Outside temperature range	0°F to 94°F
f)	Wind speeds range	0 mph to 17 mph

The drawdown analyses for secondary containment determined that the SGT system can establish and maintain the secondary containment pressure at less than 0.25 inches of vacuum water gauge within 20 minutes.

6.2.3.4 Tests and Inspections.

Components of the SGT system are tested periodically to ensure operability. The capability of the SGT system to maintain the secondary containment operability is tested in accordance with Technical Specifications. Tests are performed by isolating the secondary containment and starting either of the two SGT units. Design pressure is maintained in the secondary containment by operation of one SGT unit for a period of 1 hr. During the test, flow measurements of the SGT system and differential pressure measurements of the secondary containment are taken. If during testing the SGT system fails to maintain the secondary containment pressure at 0.25 inches of water gauge or greater below atmospheric pressure at or below an SGT system air flow rate of 2240 cfm, the reactor building is visually inspected for leakage paths. Leakage paths are repaired permanently (no temporary sealing mechanisms such as tape are used), and the tests are repeated until the acceptance level is met.

Tests are limited to 1 hr because isolation of the secondary containment necessitates the shutdown of the normal reactor building ventilation system which is required for the operation of non-ESF equipment housed in the secondary containment.

6.2.3.5 Instrumentation Requirements

Secondary containment negative pressure is automatically maintained by the reactor building pressure control system. During normal operations, this system controls the position of the blades in the normal reactor building exhaust fan units. During accident conditions, the SGTS is started and the secondary containment is isolated by the primary containment and reactor vessel isolation control system. Under this condition, the system controls reactor building negative pressure by controlling the SGT system fans.

Descriptions of the instrumentation and controls for the reactor building pressure control system, primary containment and reactor vessel isolation control system, and SGT system are contained in Section 7.3.1. The analyses are described in Section 7.3.2.

6.2.4 CONTAINMENT ISOLATION SYSTEM

6.2.4.1 Design Bases

Safety Design Bases

a. Isolation valves provide for the necessary isolation of the containment in the event of accidents or other conditions when the unfiltered release of containment contents cannot be permitted,

b. Capability for rapid closure or isolation of all pipes or ducts that penetrate the containment is achieved by means that provide a containment barrier in such pipes or ducts sufficient to maintain leakage within permissible limits,

c. The design of isolation valving for lines penetrating the containment follows the requirements of General Design Criteria (GDC) 54 through 57 as noted in Table 6.2-16,

d. Isolation valving for instrument lines which penetrate the containment conforms to the requirements of Regulatory Guide 1.11, Revision 0,

e. Isolation valves, actuators, and controls are protected against loss of safety function by missiles,

f. The design of the containment isolation valves and associated piping and penetrations is to Seismic Category I requirements,

g. Containment isolation valves and associated piping and penetrations meet the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Classes 1 or 2, as applicable, and

h. Containment isolation valve closure limits radiological effects from exceeding established requirements (10 CFR 50.67), including the effects of sudden isolation valve closure.

The primary objective of the containment isolation system is to provide protection against releases of radioactive materials to the environment as a result of accidents occurring to the nuclear boiler system, auxiliary systems, and support systems. This objective is accomplished by automatic isolation of appropriate lines that penetrate the containment system. Actuation of the containment isolation systems is automatically initiated at specific limits.

The containment isolation systems, in general, close those fluid lines penetrating containment that support systems not required for emergency operation. Those fluid lines penetrating containment which support ESF systems have remote manual isolation valves which may be closed from the control room.

Redundancy and physical separation are required in the electrical and mechanical design to ensure that no single failure in the containment isolation system prevents the system from performing its intended functions.

The isolation system is designed to Seismic Category I. Classification of equipment and systems is shown in Table 3.2-1.

Actuation of the containment isolation systems is initiated by the signals listed in Table 6.2-16.

The criteria for the design of the containment and reactor vessel isolation control system are listed in Section 7.3.1 and Table 7.3-5. The bases for assigning certain signals for containment isolation are contained in Section 7.3.1.

On signals of high drywell pressure or low-low water level in the reactor vessel, isolation valves that are part of systems not required for emergency shutdown of the plant are closed.

The same signals will initiate the operation of systems associated with the ECCS. The isolation valves which are part of the ECCS may be closed remote manually from the control room or can close automatically.

6.2.4.2 System Design

The general criteria governing the design of the containment isolation systems is provided in Sections 3.1.2 and 6.2.4.1. Table 6.2-16 summarizes the containment penetrations and contains information pertaining to:

a. Open or closed status under normal operating conditions and accident situations,
b. Primary and secondary modes of actuation provided for isolation valves,
c. Parameters sensed to initiate isolation valve closure,
d. Closure time for principal isolation valves to secure containment isolation, and
e. Applicable GDC.

Protection is provided for isolation valves, actuators, and controls against damage from missiles. All potential sources of missiles are evaluated. Where possible hazards exist, protection is afforded by separation, missile shields, or by location. See Section 3.5 for a discussion of evaluation techniques.

Isolation valves are designed to be operable under the most adverse environmental conditions (see Section 3.11) such as operation under maximum differential pressures, extreme seismic occurrences, steam laden atmosphere, high temperature, and high humidity. Electrical redundancy is provided for power-operated valves. Power for the actuation of two isolation valves in line (inside and outside of containment) is supplied by two redundant, independent power sources without cross ties. In general, outboard isolation valves receive power from a Division 1 power supply while isolation valves within containment receive power from a Division 2 power supply. In general, the supply is ac for Division 2 valves and dc for Division 1 valves depending on the system under consideration. The ability to provide appropriate containment integrity during a station blackout is discussed in Section 1.5.2.

The main steam line isolation valves are pneumatic spring-loaded, piston-operated globe valves designed to fail closed. The valves are held open by air pressure against spring force that will close or help close the valve in case of loss of power or air supply. Each main steam line isolation valve has an air accumulator to assist in its closure on loss of the air supply to the solenoid pilot valve. The separate and independent action of either air pressure or spring force will close the outboard MSIV. The inboard MSIV will close on air or springs and air.

Air-operated valves (not applicable to air-testable check valves) close on loss of air, except the butterfly valves on the RB-WW vacuum breaker lines.

The design of the isolation valve system includes consideration of the possible adverse effects of sudden isolation valve closure when the plant systems are functioning under normal operation.

6.2.4.3 Design Evaluation

6.2.4.3.1 Introduction

The main objective of the containment isolation system is to provide protection by preventing releases of radioactive materials to the environment. This is accomplished by complete isolation of system lines penetrating the primary containment. Redundancy is provided to satisfy the design requirement that any active failure of a single valve or component does not prevent containment isolation.

Mechanical components in process lines, such as isolation valve arrangements or extraordinary ex-containment system quality, are redundant and provide back-up in the event of accident conditions. Instrument lines, in many cases, rely on a single mechanical barrier in the event of accident conditions. These isolation valve arrangements satisfy the requirements specified in GDC 54, 55, 56, and 57, and Regulatory Guide 1.11, Revision 0.

The arrangements with appropriate instrumentation are described in Table 6.2-16 and Figures 6.2-36 through 6.2-59. The isolation valves have redundancy in the mode initiation. Generally, the primary mode is automatic and the secondary mode is remote manual. A program of testing, described in Section 6.2.4.4, is maintained to ensure valve operability and leaktightness.

The design specifications require each isolation valve to be operable under the most severe operating conditions. Each isolation valve is protected by separation and/or adequate barriers from the consequences of potential missiles.

Electrical redundancy is provided in isolation valve arrangements which eliminates dependency on one power source to attain isolation. Electrical cables for isolation valves in the same line have been routed separately.

Provisions are in place to control the position of nonpowered process line, vent, drain, and test connection valves that are containment isolation valves. These provisions meet the applicable requirements of GDC 55 and 56. For power-operated valves, the position is indicated in the main control room. Discussion of instrumentation and controls for the isolation valves is included in Chapter 7.

6.2.4.3.2 Evaluation Against General Design Criteria

6.2.4.3.2.1 Evaluation Against Criterion 55. The reactor coolant pressure boundary (RCPB) consists of the RPV, pressure retaining appurtenances attached to the vessel, and valves and pipes which extend from the RPV up to and including the outermost isolation valve. The lines of the RCPB which penetrate the containment include provisions for isolation of the containment, thereby precluding any significant release of radioactivity. Similarly, for lines

which do not penetrate the containment but which form a portion of the RCPB, the design ensures that isolation of the reactor coolant pressure can be achieved.

6.2.4.3.2.1.1 Influent Lines. Influent lines which penetrate the primary containment and connect directly to the RCPB are equipped with at least two isolation valves, one inside the drywell and the other as close to the external side of the containment as practical.

Table 6.2-16 contains those influent pipes that comprise the RCPB and penetrate the containment.

6.2.4.3.2.1.1.1 Feedwater Lines. The feedwater lines are part of the RCPB as they penetrate the drywell to connect with the RPV. The isolation valve inside the drywell is a swing check valve, located as close as practicable to the containment wall. Outside the containment another swing check valve is located as close as practicable to the containment wall and farther away from the containment is a motor-operated gate valve. Should a break occur in the feedwater line, the check valves prevent significant loss of reactor coolant inventory and offer immediate isolation. The design allows the condensate and condensate booster pumps to supply feedwater to the vessel through a bypass line around the reactor feed pumps (which are tripped on a loss of steam supply) as soon as the vessel is partially depressurized. For this reason, the outermost gate valve does not automatically isolate upon signal from the protection system. The gate valve meets the same environmental and seismic qualifications as the outside check valve. The valve is capable of being remotely closed from the control room to provide long-term leakage protection in the event that feedwater makeup is unavailable or unnecessary. In the control room, the operator can determine if makeup from the feedwater system is unavailable by the use of the feedwater flow indicator which will show high flow for a feedwater pipe break, or no flow for a feedwater pump trip.

The operator can also determine if makeup from the feedwater system is unnecessary by verifying that the ECCS is functioning properly and the reactor water level is being adequately maintained. The ECCS operation signals and reactor vessel water level indication are provided in the control room.

There is no need to specifically alert the operator to isolate the feedwater lines other than as described above since the lines both have check valves. However, for long-term isolation purposes, the operator may close the motor-operated gate valves at any time.

Emergency procedures require the operator to close reactor feedwater block valves within 20 minutes following cessation of feedwater flow. No credit is taken for feedwater flow in assessing core and containment response to a LOCA.

The applicable generic anticipated transients without scram (ATWS) studies (References 6.2-23 and 6.2-24) assumed the use of turbine driven feed pumps and simulated the loss of steam to the turbine and feedwater flow in the most limiting case in which all main steam lines were

isolated. In the ATWS situation, the loss of feedwater flow (or limiting of the flow to near zero) causes a decrease in core flow and inlet subcooling which results in a power reduction. This leads to a benefit in mitigating the peak vessel pressure, containment pressure and suppression pool temperature.

6.2.4.3.2.1.1.2 High-Pressure Core Spray Line. The HPCS line penetrates the drywell to inject directly into the RPV. Isolation is provided by a check valve located inside the drywell, and a remote-manually actuated gate valve located as close as practicable to the exterior wall of the containment. Long-term leakage control is maintained by this gate valve. If a LOCA occurred, the gate valve would receive an automatic signal to open.

6.2.4.3.2.1.1.3 Low-Pressure Coolant Injection Lines. Satisfaction of isolation criteria for the three LPCI injection lines of the RHR system is accomplished by use of remote-manually operated gate valves and check valves. Both types of valves are normally closed with the gate valves receiving an automatic signal to open at the appropriate time to ensure that acceptable fuel design limits are not exceeded in the event of a LOCA. The check valves are located as close as practicable to the RPV. The normally closed check valves protect against overpressurization in the reactor coolant pressure boundary (RCPB) by preventing high-pressure reactor water from entering the RHR system low pressure piping. When the reactor pressure is lower than the RHR system pressure, the low energy of the influent fluid (220°F maximum) can open the check valve and inject water into the reactor.

6.2.4.3.2.1.1.4 Control Rod Drive Lines. The CRD system insert and withdraw lines penetrate the drywell. The classification of these lines is Code Group B and they are designed in accordance with ASME Section III, Class 2. The basis to which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining pressure integrity of these lines. The Hydraulic Control Units (HCUs) and scram discharge headers as well as the hydraulic lines are Seismic I, and are qualified to the appropriate accident environment. The failure and scram position of all power operated valves are compatible with system isolation and, at the same time, rod insertion on a scram.

The inboard isolation of insert and withdraw lines for the primary containment is provided by the double seals in the control rod drives and the outboard isolation for the primary containment is provided by valves within the HCUs. The HCU manual isolation valves 101 and 102 are provided for positive isolation in the unlikely event of a pipe break within the HCU. Additional isolation is provided by normally closed, fail-closed, solenoid operated Directional Control Valves (DCV) in the HCUs (see Figure 4.6-5). The DCVs open only during routine movement of their associated control rod and during a reactor scram. In addition, a ball check valve located in the CRD flange housing automatically seals the insert line in the event of a break.

Insert and withdraw lines that extend outside the primary containment are small and terminate in the Reactor building which is served by the SGT system. Containment overpressurization

will not result from a line break in containment since these lines contain small volumes at low energy levels. External leak detection of CRD piping outside of primary containment is provided by operations during routing routine inspections.

Two Quality Class I check valves in series (CRD-V-524/525) are located at the discharge of the CRD pumps to prevent significant bypass leakage through the Quality Class II CRD piping to the condensate storage tank that could result if any leakage past the HCU were to exist. If the Quality Class II CRD piping breaks between the check valves and the CRD HCUs, the SGT system will process the effluent prior to release from secondary containment. Thus, the potential bypass path by means of this CRD path is minimized to prevent any significant offsite consequence.

The NRC staff concluded in NUREG-0803, "Safety Evaluation Report Regarding Integrity of BWR Scram Systems," that although the CRD system represents a departure from GDC 55, the CRD containment isolation provision stated above is considered acceptable.

6.2.4.3.2.1.1.5 Residual Heat Removal and Reactor Core Isolation Cooling Head Spray Lines. The RHR head spray and RCIC lines meet outside the containment to form a common line which penetrates the drywell and discharges directly into the RPV. The check valve inside the drywell is normally closed. The check valve is located as close as practicable to the RPV. Two remote-manual block valves are utilized as isolation valves located outside the containment. The check valve ensures immediate isolation of the containment in the event of a line break. The block valve on the RHR line receives an automatic isolation signal while the block valve on the RCIC line is remote manually actuated to provide long-term leakage control.

6.2.4.3.2.1.1.6 Standby Liquid Control System Lines. The standby liquid control system line penetrates the drywell and connects to the HPCS system injection line. In addition to a check valve inside the drywell, a parallel pair of explosive actuated valves are located outside the drywell. Since the standby liquid control line is a normally closed, nonflowing line, rupture of this line is extremely remote. The explosive actuated valves function as outboard isolation valves. These valves provide a seal for long-term leakage control as well as preventing leakage of sodium pentaborate into the RPV during SLC system testing.

6.2.4.3.2.1.1.7 Reactor Water Cleanup System. The RWCU pumps, heat exchangers, and filter demineralizers are located outside the drywell. The return line from the filter demineralizers connects to the feedwater line outside the containment between the block valve and the outside containment feedwater check valve. Isolation of this line is provided by the feedwater system check valve inside the containment, the feedwater system check valve outside the containment, and an RWCU motor-operated gate valve outside the containment. The motor-operated gate valve functions as a third isolation valve.

During the postulated LOCA, it may be desirable to restore reactor coolant cleanup. For this reason, the motor-operated gate valve in the RWCU return line does not automatically isolate upon a containment isolation signal. If reactor coolant cleanup is not required, the return isolation valve RWCU-V-40 can be shut remotely from the control room when the motor-operated feedwater block valves are closed 20 minutes or more after the beginning of a LOCA. Should a break occur in the reactor water cleanup return line, the check valves would prevent significant loss of inventory and offer immediate isolation, while the outermost isolation valve would provide long-term leakage control.

6.2.4.3.2.1.1.8 Recirculation Pump Seal Water Supply Line. The recirculation pump seal water line extends from the recirculation pump through the drywell and connects to the CRD supply line outside the primary containment. The seal water line forms a part of the RCPB. The recirculation pump seal water line is Code Group B from the recirculation pump through the outboard motor operated isolation valve. From this valve to the CRD connection the line is Code Group D. Should this line fail, the flow rate through the broken line has been calculated to be substantially less than that experienced by a broken instrument line.

6.2.4.3.2.1.1.9 Low-Pressure Core Spray Line. The LPCS line penetrates the drywell to inject directly into the RPV. Isolation is provided by a check valve located inside the drywell and a remote-manually actuated gate valve located as close as practicable to the exterior wall of the containment. Long-term leakage control is maintained by this gate valve. If a LOCA occurs, this gate valve will receive an automatic signal to open, delayed only by control circuitry that ensures that the fluid pressure inside the RPV is less than the design pressure of the piping.

6.2.4.3.2.1.1.10 Residual Heat Removal Shutdown Cooling Return Lines. The two shutdown cooling return lines inject into the RRC lines downstream of the RRC pumps. Isolation is accomplished by a normally-closed, motor-operated gate valve outside containment and the parallel arrangement of a full-flow check valve and a normally closed, partial-flow, motor-operated gate valve inside the containment. Both motor-operated valves receive signals to close if RHR system water is needed to support the ECCS mode of the RHR system.

6.2.4.3.2.1.2 Effluent Lines. Effluent lines which form part of the RCPB and penetrate containment are equipped with at least two isolation valves; one inside the drywell and the other outside, located as close to the containment as practicable.

Table 6.2-16 also contains those effluent lines that comprise the RCPB and which penetrate the containment.

6.2.4.3.2.1.2.1 Main Steam, Main Steam Drain Lines, and Residual Heat Removal/Reactor Core Isolation Cooling Steam Supply Lines. The main steam lines extend from the RPV to the main turbine and condenser system, and penetrate the primary containment. Isolation is afforded inside by a normally-open, fail-close, automatic, air-operated, y-pattern globe valve

and outside by a similar in-line globe valve paralleled by smaller automatic motor-operated gate valves, one each in the between-MSIV drain line and in the MSLC system tap (isolated – MSLC system is deactivated). The main steam drain line, which comes off a common manifold tapping off each main steam line just upstream of each inside MSIV, also penetrates the containment and is isolated by automatic motor-operated gate valves, one inside the containment and one outside the containment. The RHR steam supply line and RCIC turbine steam line connect to the main steam line inside the drywell and penetrate the primary containment. For these lines, isolation is provided by automatically actuated block valves, two parallel valves inside the containment common to both the RHR steam supply line and the RCIC turbine steam line, and one for each line just outside the containment. The outside RHR steam supply line isolation valve has been deactivated and locked in the closed position.

6.2.4.3.2.1.2.2 Recirculation System Sample Lines. A 0.75-in. diameter sample line from the recirculation system penetrates the drywell and is designed to ASME, Section III, Class l. A sample probe with a 1/8-in. diameter hole is located inside the recirculation line inside the drywell. In the event of a line break, the probe acts as a restricting orifice and limits the escaping fluid. Two automatic valves which fail close are provided; one inside and one outside the containment.

6.2.4.3.2.1.2.3 Reactor Water Cleanup System. The RWCU pumps, heat exchangers, and filter demineralizers are located outside the drywell. The supply line to the RWCU system connects to the reactor recirculation system lines on the suction side of the reactor recirculation pumps and to the RPV by means of the RPV drain line. Isolation of the RWCU lines is provided by two automatically actuated motor-operated gate valves. One valve is located inside containment and the other is located outside containment. Both valves are capable of remote manual operation from the control room.

6.2.4.3.2.1.2.4 Residual Heat Removal Shutdown Cooling Line. This line is common to the two trains of RHR shutdown cooling and is located on the A train RRC line just upstream of the pump. The inside motor-operated isolation gate valve, located as close as practical to the RPV, is paralleled by a small check valve. The valve is oriented to relieve a pressure build-up in the long section of line between the inside isolation valve and the outside isolation valve during those times when both valves are closed and the trapped line fluid heats and expands. The outside motor-operated containment isolation gate valve is located as close as practical to the containment. Both motor-operated valves automatically isolate on Level 3 to prevent further inventory loss in the event of a line break.

6.2.4.3.2.1.3 Conclusion on Criterion 55. To ensure protection against the consequences of accidents involving the release of radioactive material, pipes which form the RCPB have been shown to provide adequate isolation capabilities. A minimum of two barriers were shown to protect against the release of radioactive materials.

In addition to meeting the isolation requirements stated in Criterion 55, the pressure retaining components which comprise the RCPB are designed to meet other appropriate requirements which minimize the probability or consequences of an accidental pipe rupture. The quality requirements for these components ensure that they are designed, fabricated, and tested to the highest quality standards of all reactor plant components. The classification of components which comprise the RCPB are designed in accordance with the ASME, Section III, Class 1.

Therefore, design of piping system which comprises the RCPB and penetrates containment satisfies Criterion 55.

6.2.4.3.2.2 Evaluation Against Criterion 56. Criterion 56 requires that lines which penetrate the containment and communicate with the containment interior must have two isolation valves, one inside the containment and one outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

Table 6.2-16 includes those lines that penetrate the primary containment and connect to the drywell and suppression chamber.

For the lines wherein only a single isolation valve exists, the discussion in Section 6.2.4.3.2.2.1.1 is germane. Also see Table 6.2-16 for further information on specific lines.

For those lines wherein both isolation valves are located outside containment, the discussions in Sections 6.2.4.3.2.2.3.2, 6.2.4.3.2.2.3.10 and 6.2.4.3.2.2.3.11 apply. Also see Table 6.2-16 for further information on specific lines such as the HCV system.

6.2.4.3.2.2.1 Influent Lines to Suppression Pool.

6.2.4.3.2.2.1.1 Low-Pressure Core Spray, High-Pressure Core Spray, and Residual Heat Removal Test and Minimum Flow Bypass Lines. The LPCS, HPCS, and RHR test lines have test isolation capabilities commensurate with the importance to safety of isolating these lines. Each line has a normally closed, motor-operated valve located outside the containment. Containment isolation requirements are met on the basis that the test lines are closed, low pressure lines constructed to the same quality standards as the containment. Furthermore, these lines are connected to ESF systems for which a single isolation valve is acceptable [as stated in NRC Standard Review Plan (SRP) 6.2.4, Section II, paragraph 6.e] based on the following prerequisites:

a. System reliability is improved with only one isolation valve in the line,

b. The system is closed outside containment and a single active failure can be accommodated with only one isolation valve,

c. The closed system is protected from missiles,

d. The closed system is designed to Seismic Category I, Safety Class 2, requirements and a minimum temperature and pressure rating at least equal to that for the containment, and

e. The piping between the isolation valve and containment is enclosed in the leak-tight housing, or conservative design of the piping and valve, conforming to SRP 3.6.2, precludes a breach of piping integrity.

The test return lines are also used for suppression chamber return flow during other modes of operation. In this manner the number of penetrations is reduced, minimizing the potential pathways for radioactive material release. Typically, pump minimum flow bypass lines join the respective test return lines downstream of the test return isolation valve. The bypass lines are isolated by motor-operated valves with a restricting orifice downstream of the motor-operated valve.

6.2.4.3.2.2.1.2 Reactor Core Isolation Cooling Turbine Exhaust, Vacuum Pump Discharge, and RCIC Pump Minimum Flow Bypass Lines. These lines, which penetrate the containment and discharge to the suppression pool, are equipped with a motor-operated, remote manually actuated gate valve located as close to the containment as possible. In addition, there is a simple check valve upstream of the gate valve which provides positive actuation for immediate isolation in the event of a break upstream of the check valve. The gate valve in the RCIC turbine exhaust is key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not in a full open position. The RCIC vacuum pump discharge line is also normally open but has no requirement for interlocking with steam inlet to the turbine. The RCIC pump minimum flow bypass line is isolated by a normally closed valve. The single valve is allowable because the water side of the RCIC system is a closed system analogous to the lines discussed in Section 6.2.4.3.2.2.1.1.

6.2.4.3.2.2.1.3 Residual Heat Removal Heat Exchanger Vent Lines. The RHR heat exchanger vent lines discharge through the RHR heat exchanger relief valve discharge lines to the suppression pool. Two globe valves in each vent line provide the system pressure boundary and are used to control venting during the RHR heat exchanger filling and draining operations. The outboard globe valve in each line is and meets the criteria for a containment system isolation valve. Both valves are normally closed, remotely controlled motor-operated globe valves. Each vent line is also equipped with a manual block valve and the test connections necessary for Type C testing of the isolation valve.

6.2.4.3.2.2.1.4 Low-Pressure Core Spray, High-Pressure Core Spray, and Residual Heat Removal Relief Valve Discharge Lines. These relief valves discharge to the suppression pool

directly. They will not normally lift during operation and, therefore, can be considered as normally closed.

6.2.4.3.2.2.1.5 Fuel Pool Cooling and Cleanup Return Lines. Line is isolated by two normally-closed automatically actuated motor-operated gate valves, which are located outside the containment per NRC SRP 6.2.4, Section II, paragraph 6.d.

6.2.4.3.2.2.1.6 Deactivated Residual Heat Removal Steam Condensing Mode Steam Line Relief and Drain Lines. The four steam line relief valves (two per train) have been removed and the line flanges are blanked by "structural connections."

The two parallel-installed drain pot motor-operated globe valves (per train) are deactivated electrically and locked closed to maintain compliance with Criterion 56. Single isolation barriers are warranted on the basis that the RHR system is a closed system.

The RHR heat exchanger vents and relief valves along with the disabled CAC hydrogen recombiner drains and the discharge from RHR-RV-30 return to the wetwell through the deactivated steam condensing mode lines.

6.2.4.3.2.2.1.7 Process Sampling Suppression Pool Sample Return Line. Dual normally closed remote manual solenoid valves offer containment isolation. The valves are located outside the containment based on NRC SRP 6.2.4, Section II, paragraph 6.d.

6.2.4.3.2.2.2 Effluent Lines From Suppression Pool.

6.2.4.3.2.2.2.1 High-Pressure Core Spray, Low-Pressure Core Spray, Reactor Core Isolation Cooling, and Residual Heat Removal Suction Lines. These lines contain motor-operated, remote manually actuated, gate valves which provide assurance of isolating these lines in the event of a break. These valves also provide long-term leakage control. In addition, the suction piping from the suppression chamber is considered an extension of containment since it must be available for long-term usage following a design basis LOCA and, as such, is designed to the same quality standards as the containment. Thus, the need for isolation is conditional. The ECCS and RCIC fill systems (ECCS waterleg pumps) take suction from ECCS pump suppression pool suctions downstream of the isolation valve. This system is isolated from the containment by the respective ECCS pump suction valve from suppression pool as listed in Table 6.2-16.

6.2.4.3.2.2.2.2 Fuel Pool Cooling Suction Line. Two normally closed automatic motor-operated gate valves, located outside the containment (based on NRC SRP 6.2.4, Section II, paragraph 6.d), provide containment isolation.

6.2.4.3.2.2.2.3 PSR Suppression Pool Sample Line. Dual normally-closed remote manual solenoid valves offer containment isolation. The valves are located outside the containment (based on NRC SRP 6.2.4, Section II, paragraph 6.d).

6.2.4.3.2.2.3 Influent and Effluent Lines From Drywell and Suppression Chamber Free Volume.

6.2.4.3.2.2.3.1 Containment Atmosphere Control Lines (Deactivated). The containment atmosphere control system lines which penetrate the containment are equipped with two power-operated valves in series, normally closed. Since the CAC system has been deactivated, these valves have been de-energized. The motor operated gate valves have been locked closed, and the electrohydraulic operated valves are de-energized spring-closed. These valves provide assurance of isolating these lines in the event of a break and also provide long-term leakage control. In addition, the piping is considered an extension of containment boundary since it must remain intact following a design basis LOCA and, as such, is designed to the same quality standards as the primary containment.

6.2.4.3.2.2.3.2 Containment Purge Supply, Exhaust, and Inerting Makeup Lines. The drywell and suppression chamber purge lines have isolation capabilities commensurate with the importance to safety of isolating these lines. Each line has two air-operated spring closing isolation valves located outside the primary containment that are fully qualified to close under accident conditions. Containment isolation requirements are met on the basis that the purge lines are low pressure lines constructed to the same quality standards as the containment. Valve operability and reliability are enhanced by placement of both valves outside of the containment. The isolation valves for the purge lines are interlocked to preclude their being opened while a containment isolation signal exists as noted in Table 6.2-16.

Stainless-steel grills are installed across both purge supply line openings (one low in the drywell and the other low in the suppression chamber) and across the purge exhaust line opening high in the drywell. These prohibit debris from entering the purge lines, thus preventing the isolation valves from seating. The two remaining line openings (one purge exhaust and the single vacuum relief line that is not tied into a purge line, both of which are high in the suppression chamber) do not require debris screens because there is no probability of airborne debris during an accident (pipe insulation is not used in the suppression chamber) and the maximum anticipated suppression pool swell elevation is not sufficient to bring the surface of the water to either of these two openings.

There is a small branch line, which provides a makeup supply of nitrogen to inert containment, connected to the purge supply lines for both the drywell and suppression chamber. Each nitrogen makeup taps into its associated purge supply line inboard of the air-operated, spring-closing isolation valves. Therefore, each of these nitrogen lines is equipped with two automatic containment isolation valves, located as close as possible to primary containment.

6.2.4.3.2.2.3.3 Drywell and Suppression Chamber Air Sampling Lines. The radiation monitor lines penetrate the primary containment and are used for continuously sampling containment air during normal operation as part of the leak detection system. The supply lines are equipped with two automatic solenoid-operated isolation valves located outside and as close as possible to the containment. The return lines are equipped with a remotely operated solenoid isolation valve outside of containment and a check valve inside the containment.

The PSR system sample and return lines are normally isolated by dual solenoid valves. These do not receive automatic isolation signals since they may be used to sample the drywell and suppression chamber atmosphere in a post-LOCA situation.

6.2.4.3.2.2.3.4 Suppression Chamber Spray Lines. The suppression chamber spray lines penetrate the containment to remove energy by condensing steam and cooling noncondensable gases in the suppression chamber. Each line is equipped with a normally closed motor-operated valve located outside and as close as possible to the primary containment. This normally closed valve receives an automatic isolation signal. Containment isolation requirements are met on the basis that the spray header injection lines are normally closed, low pressure lines constructed to the same quality standards as the containment.

6.2.4.3.2.2.3.5 Reactor Building to Wetwell Vacuum Relief Lines. The three RB-WW vacuum relief lines are each equipped with a positive closing swing check valve in series with an air-operated, fail-open, butterfly valve. The air operator on the swing check valve is used only for testing. The air-operated butterfly valve is controlled by a differential pressure indicating switch which senses the pressure difference between the suppression chamber and the reactor building. When the negative pressure in the suppression chamber exceeds the instrument setpoint, the butterfly valve opens. The valves are not susceptible to fouling by ingested debris during such an event because they are not targets of missiles and are adequately protected from pipe break damage. The arrangement of valves and instruments is shown in Figure 9.4-8.

6.2.4.3.2.2.3.6 Drywell Spray Lines. The drywell spray lines are equipped with two normally closed, motor-operated gate valves located outside and as close as possible to primary containment. The drywell spray must be manually initiated. The piping from the outermost isolation valve to the spray ring header is constructed to withstand containment design conditions.

6.2.4.3.2.2.3.7 Reactor Closed Cooling Water Supply and Return Lines. Dual motor-operated automatic gate valves isolate each line, the former having both outside the containment and the latter having one inside and one outside the containment. In response to the concerns addressed in Generic Letter 96-06, Energy Northwest installed a bypass line around the inboard isolation valve on the return line. This bypass line is equipped with a check valve oriented against normal system flow. Thus, the check valve functions as an

isolation valve in parallel with the main inboard isolation valve and as a means to dissipate pressure built up between the inboard and outboard isolation valves.

6.2.4.3.2.2.3.8 Air Supply Lines.

6.2.4.3.2.2.3.8.1 Check Valve Air Supply Lines. All lines are isolated by two locked-closed manual globe valves located outside the containment and as close as practical to the containment. The air test function is not used. Therefore, the valves are normally closed all of the time.

6.2.4.3.2.2.3.8.2 Primary Containment Instrument Air System Nitrogen Supply Lines. These lines consist of a check valve inside the containment and a motor-operated remote-manual globe valve outside the containment. The globe valves are under the control of the operator who can isolate the single nonsafety-related header should the containment nitrogen (CN) supply be unavailable. The operator can also isolate either or both safety-related headers should either, or both, experience nitrogen supply problems or otherwise require isolation. See Table 6.2-16 for further information.

6.2.4.3.2.2.3.8.3 Service Air System Maintenance Supply Line to the Drywell. This single line is capped with a threaded pipe cap inside the containment and isolated outside the containment by a locked-closed manual globe valve.

6.2.4.3.2.2.3.9 Demineralized Water Maintenance Supply Line to the Drywell. Dual manual gate valves, one inside and one outside the containment, isolate this line at all times except when high purity water is required inside the drywell for maintenance-related activities.

6.2.4.3.2.2.3.10 Drywell Equipment and Floor Drain Lines. Containment isolation is provided by two normally open, air-operated, fail-close automatic valves located outside and as close as practical to the containment.

6.2.4.3.2.2.3.11 Traversing In-Core Probe (TIP) System Guide Tubes. The TIP system consists of five guide tubes which penetrate the containment and interface with the containment atmosphere because of indexer leakage and built-in relief valves that prevent the indexers from collapsing on high pressure. The isolation design basis for these TIP lines is a “specific class of line” considered acceptable under General Design Criterion 56.

Isolation is accomplished by a seismically qualified solenoid-operated ball valve, which is normally closed. To ensure isolation capability, an explosive shear valve is installed in each line. Upon receipt of a signal (manually initiated by the operator) this explosive valve will shear the TIP cable and seal the guide tube.

When the TIP system is inserted, the ball valve of the selected tube opens automatically so that the probe and cable may advance. A maximum of five valves may be opened at any one time to conduct calibration and any one guide tube is used, at most, a few hours per year.

If closure of the line is required during calibration, a signal causes a cable to be retracted and the ball valve to close automatically after completion of cable withdrawal. If a TIP cable fails to withdraw or a ball valve fails to close, the explosive shear valve is actuated. The ball valve position is indicated in the control room.

The ball valve and shear valve are located outside the drywell and as close as practical to the containment. These valves are designed to Code Group B requirements, therefore they are of the same quality class as the containment.

6.2.4.3.2.2.4 Conclusion on Criterion 56. To ensure protection against the consequences of accidents involving release of significant amounts of radioactive materials, pipes that penetrate the containment have been demonstrated to provide isolation capabilities in accordance with Criterion 56 or other defined bases.

In addition to meeting the above isolation requirements, the pressure retaining components of most of these systems are designed to the same quality standards as the containment. For exceptions, see Section 6.2.4.3.2.4.

6.2.4.3.2.3 Evaluation Against Criterion 57. Lines forming a closed system outside the primary reactor containment must have one isolation valve outside if the system boundary penetrates the containment. All closed systems outside primary containment at Columbia have at least one isolation valve if they penetrate primary containment which provides isolation capabilities in accordance with Criterion 57.

6.2.4.3.2.4 Evaluation Against Regulatory Guide 1.11, Revision 0. Instrument lines which penetrate the containment from the RCPB are equipped with a restricting orifice located inside the drywell and an excess flow check (EFC) valve located outside and as close as practicable to the containment. Those instrument lines which do not connect to the RCPB are equipped with single solenoid-operated or EFC isolation check valves. Valve position indication is available in the control room.

The EFC valves have no active safety function requirements. However, the RCPB instrument line EFC valves close to limit the flow in the respective instrument lines in the event of an instrument line break downstream of the EFC valve outside containment. The instrument lines are Seismic Category I and are assumed to maintain integrity for all accidents except for the instrument line break accident (ILBA) as described in Section 15.6.2. Isolation of the instrument line by the EFC valve is not credited for mitigating the ILBA.

Each EFC valve has an integral manual bypass valve which may be used to reset an actuated disc. The bypass valves are periodically verified to be closed.

The hydrogen/oxygen monitoring lines penetrate primary containment and are used to continuously monitor the containment air during the post-LOCA accident period. These lines are equipped with single solenoid-operated or EFC valves located outside and as close as possible to the containment. Containment isolation requirements are met on the basis that these are low pressure lines constructed to the same quality standards as the containment. The solenoid-operated valves are required to remain open during normal operation and postaccident for those DBAs for which containment isolation is required to limit offsite dose consequences to less than established requirements. Accordingly, they receive no automatic isolation signal or leak rate testing. No credit is taken for either the automatic or remote manual closing of these valves for containment isolation for the DBAs. Therefore, position indication requirements do not apply to the solenoid-operated valves.

6.2.4.3.3 Failure Mode and Effects Analyses

In single failure analysis of electrical systems, no distinction is made between mechanically active or passive components. All fluid system components such as valves are considered electrically active whether or not mechanical action is required.

Electrical as well as mechanical systems are designed to meet the single failure criterion for both mechanically active and passive fluid system components regardless of whether that component is required to perform a safety action. Even though a component such as an electrically operated valve is not designed to receive a signal to change state (open or closed) in a safety scheme, it is assumed as a single failure that the system component changes state or fails. Electrically operated valves include those that are electrically piloted but air operated as well as those that are directly operated by an electrical device. In addition, all electrically operated valves that are automatically actuated can also be manually actuated from the main control room. Therefore, a single failure in any electrical system is analyzed regardless of whether the loss of a safety function is caused by a component failing to perform a requisite mechanical motion or a component performing an unnecessary mechanical motion.

6.2.4.3.4 Operator Actions

A trip of an isolation control system channel is annunciated in the main control room. Most motor-operated and air-operated isolation valves have open-close status lights. The following general information is presented to the operator by the isolation system:

a. Annunciation of each process variable which has reached a trip point,

b. Computer readout of trips on main steam line tunnel temperature or main steam line excess flow,

c. Control power failure annunciation for each channel, and

d. Annunciation of steam leaks in each of the systems monitored (main steam, reactor water cleanup, and reactor heat removal).

If the primary containment and reactor vessel isolation system does not automatically shut an isolation valve, the "isolation signal" column of Table 6.2-16 references the applicable note which discusses the isolation criteria including operator action based on specific input available to the operator.

This information will enable the operator to determine the need to operate a remote manual valve in the event of a LOCA.

6.2.4.4 Tests and Inspections

The containment isolation system is periodically tested during reactor operation and shutdown. The functional capabilities of power operated isolation valves are tested remote manually from the main control room. By observing position indicators and/or changes in the affected system operation, the closing ability of a particular isolation valve is demonstrated. A discussion of testing and inspection pertaining to isolation valves is provided in Section 6.2.1. Table 6.2-16 lists the process line isolation valves.

The EFC valves used as single reactor instrument sensor line isolation valves are periodically tested to meet the requirements of Regulatory Guide 1.11 and the Technical Specifications Surveillance Requirements. As these valves are outside the containment and accessible, periodic visual inspection is performed in addition to the operational check. Sensor lines emanating from the suppression pool, the suppression chamber, or the drywell free volume are periodically tested on a sampling basis in accordance with the plant maintenance program.

Preoperational testing is discussed in Section 14.2.12. Containment isolation valve leakage rate testing is discussed in the notes in Figures 6.2-36 through 6.2-59.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Combustible gas control is provided to ensure containment integrity when hydrogen and oxygen gases are generated following a postulated LOCA. The RHR system operating in containment spray mode and redundant reactor head area return fans augment the natural processes to mix the containment atmosphere. The oxygen and hydrogen concentrations in the containment atmosphere are monitored by instrumentation discussed in Section 7.5.1.5. To supplement the combustible gas control system, the containment nitrogen inerting system provides a nitrogen atmosphere in primary containment.

6.2.5.1 Design Bases

The design bases for the containment atmosphere control system are as follows:

a. The system is designed in accordance with 10 CFR 50.44;

b. Primary containment will be inerted to an oxygen concentration of less than or equal to 3.5% by volume during normal plant operation;

c. Containment sprays, natural turbulence resulting from diffusion and convection caused by the elevated temperatures, and operation of the containment head area return fans, if necessary, ensure that no local pocket with greater than 5% oxygen can occur within containment;

6.2.5.2 System Design

The system consists of the following:

a. An atmosphere mixing system which could operate if necessary to ensure a well mixed atmosphere in both the drywell and suppression chamber. This system consists of the containment spray system which can be actuated approximately 10 minutes after the postulated LOCA, and containment head area return fans which start on receipt of a reactor scram signal;

b. A monitoring system measures the concentration of hydrogen and oxygen in the drywell and suppression chamber atmosphere; and

c. Two hydrogen-oxygen recombiners are deactivated and isolated from primary containment. Attached piping and components are similarly deactivated, retaining solely their structural continuity with the containment penetrations. The recombiners are Seismic Category I.

6.2.5.2.1 Atmosphere Mixing System

The function of the atmosphere mixing system is to provide a well mixed atmosphere in the drywell and suppression chamber.

Using experimental results (Reference 6.2-18) as a basis for hydrogen and oxygen mixing within the containment, hydrogen or oxygen distribution in the steam nitrogen-oxygen atmosphere would simulate that of the iodine fission products (References 6.2-19 and 6.2-20) and it would be uniform throughout the containment. Accordingly, it is extremely unlikely that an atmosphere mixing system would be required.

However, the RHR system operating in containment spray mode and redundant reactor head area return fans are available to augment these natural processes.

The RHR system containment spray system is described in Section 5.4.7. It may be manually actuated from the main control room to provide mechanical mixing of the drywell atmosphere.

The two head area return fans are part of the primary containment cooling system, discussed in Section 9.4.11.2.

The redundant reactor head area return fans are available to exhaust atmospheric gases and vapors from the reactor head area above the refueling bulkhead plate to the main portion of the drywell. Both fans start automatically upon reactor scram and are powered from different Class 1E electrical divisions. Atmospheric gases and vapors exhausted from the reactor head area by the fan(s) are replaced by flow from the drywell area through the two vent paths through the bulkhead plate as portrayed in Figure 6.2-24. This recirculation prevents formation of pockets of combustible gases both in the reactor head area and in the drywell below the bulkhead plate.

6.2.5.2.2 Hydrogen and Oxygen Concentration Monitoring System

Both the oxygen and the hydrogen concentrations are continuously monitored during normal operation and following the postulated LOCA, and are displayed in the control room. A visual and audible alarm initiates in the control room if the oxygen concentration reaches 3.5% by volume. This alarm alerts operators to take action to limit the pre-LOCA oxygen concentration to 3.5% or less to ensure that post-LOCA oxygen concentrations will not exceed the limit of 4.8%. If oxygen concentration approaches 4.4% by volume, a visual and audible high-high level alarm initiates in the control room.

The hydrogen and oxygen gas analyzers, number and location of sampling points, and instrumentation are discussed in Section 7.5.1.5.

Calibration tests are routinely performed to calibrate and verify instrument accuracy against known gas compositions.

Two redundant hydrogen and oxygen concentration monitoring systems are provided.

6.2.5.2.3 Containment Purge

Containment purge is discussed in Section 6.2.1.1.8.

6.2.5.3 Design Evaluation

The determination of the time-dependent oxygen and hydrogen concentrations in the drywell and suppression chamber atmospheres is based on a two-region model of the primary containment: a drywell and suppression chamber atmosphere. The rate of radiolytic hydrogen and oxygen generation varies linearly with power.

The released fission products, excluding noble gases, that are mixed with the coolant are assumed to be swept out of core as the core cooling waters exit the break and flow by gravity by means of the downcomers to the suppression chamber.

Hydrogen generated from the metal-water reaction and both hydrogen and oxygen generated from core radiolysis are assumed released to the drywell atmosphere and mix homogeneously. Hydrogen as well as oxygen generated from suppression pool radiolysis are assumed released to the suppression chamber atmosphere and mix homogeneously.

The hydrogen and oxygen monitors are accurate at the anticipated concentration in the primary containment.

6.2.5.3.1 Hydrogen and Oxygen Generation

In the period immediately after the postulated LOCA, hydrogen can be generated by radiolysis, metal-water, and metallic paint-water reactions. However, in evaluating short-term hydrogen generation, the contribution from radiolysis and metallic paint-water reactions are insignificant in comparison with the hydrogen generated by the metal-water reaction.

During the same time period oxygen is generated by radiolysis only. However, the contribution from radiolysis is small compared with the initial 3.5% oxygen concentration within containment prior to the postulated LOCA.

The generation of hydrogen by metal-water reaction is dependent on the temperature of the cladding at the time the postulated LOCA occurs. Based on LOCA calculations and ECCS performance in accordance with 10 CFR 50.46, the extent of metal-water reaction in the BWR/5 core is negligible. The design of the BWR/5 ECCS is such that the peak Zircaloy clad temperature is less than 2000°F. At this temperature virtually no metal-water reaction occurs and, therefore, hydrogen production by this means is insignificant.

6.2.5.4 Testing and Inspections

The RHR drywell spray mode of operation is tested in accordance with Technical Specifications. The head area return fan testing is discussed in Section 9.4.11.4. Testing of the hydrogen and oxygen monitoring is discussed in Section 7.5.1.5.4.

6.2.5.5 Instrumentation Requirements

See Sections 7.5.1.5.4 and 9.4.11.5.

6.2.5.6 Materials

See Section 6.2.5.2.

6.2.5.7 Containment Nitrogen Inerting System

The system is designed to establish and maintain a nitrogen atmosphere in which the oxygen concentration can be controlled at less than 3.5% by volume in both the drywell and suppression pool during normal operation. The system is designed to comply with NRC staff position of April 2, 1981, requiring that "the GE pressure suppression containment systems identified by Mark I and Mark II, be inerted."

6.2.6 CONTAINMENT LEAKAGE TESTING

General Design Criteria 52, 53, and 54 have been met.

6.2.6.1 Containment Leakage Rate Tests

The primary containment system is a steel pressure suppression system of the over and under configuration with a designed leakage rate of 0.5% by volume per day at 45 psig. A maximum allowable integrated vessel leak rate of 0.5% by weight per day at 38 psig has been established to limit leakage during and following the postulated DBA to less than that which would result in offsite doses greater than those specified in 10 CFR 50.67. Leakage rate tests at reduced pressures may be established such that the measured leakage rate does not exceed the maximum allowable at that reduced pressure.

A structural integrity test involving pneumatic pressurization of the drywell and suppression chamber was performed at 51.8 psig, 1.15 times the containment vessel design pressure of 45 psig. This test was conducted in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition through the Summer 1972 Addenda, Subarticle NE-6300. See Section 3.8.2.7 for a description of the test.

Testing involves performing periodic Type A, B, and C tests. These tests are conducted in accordance with the Technical Specifications and 10 CFR 50, Appendix J. Table 6.2-14 lists the containment penetrations subject to Type B tests. Table 6.2-16 lists the primary containment isolation valves subject to Type C tests unless otherwise noted.

6.2.6.2 Special Testing Requirements

The secondary containment is tested at each refueling outage to ensure the maximum allowable leakage rate of 100% of secondary containment free volume per day at negative 0.25-in. water gauge pressure with respect to outside atmospheric pressure. Further testing is summarized in Section 6.2.3.4. Other testing requirements are contained in the Technical Specifications.

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Table 6.2-1

Containment Design Parameters

			Drywell	Suppression Chamber
A.	Drywell and Suppression Chamber			
	1.	Internal design pressure, psig	45	45
	2.	External design pressure, psig	2	2
	3.	Drywell deck design differential pressure, psid	25 (downward) 6.4 (upward)	
	4.	Design temperature, °F	340	275
	5.	Net free volume, ft^3 (drywell includes vents)	200,540	144,184 maximum
	6.	Maximum allowable leak rate, %/day	0.5	0.5
	7.	Suppression chamber free volume, minimum, ft^3		142,500
	8.	Suppression chamber water volume minimum,[a] ft^3		112,197
	9.	Pool cross section area, ft^2		5,770
	10.	Pool free surface cross section area, ft^2		4,520
	11.	Pool depth (normal), ft		31
B.	Vent System			
	1.	Number of downcomers		99
	2.	Downcomer inside diameter, ft		1.995
	3.	Total vent area, ft^2		309
	4.	Downcomer maximum submergence, ft		12
	5.	Downcomer loss factor		2.77

[a] This volume does not include the water within the pedestal (10,065 ft^3) nor the water 12 ft below the downcomer exits (15,000 ft^3)

Table 6.2-2

Engineered Safety Systems Information
for Containment Response Analyses

	Full Capacity	Value Used in Containment Analysis			
		Case A	Case B	Case C	Reduced ECCS Flow Case C
A. Drywell Spray System					
1. Number of pumps	2	2	1	N/A	N/A
2. Number of lines	2	2	1	N/A	N/A
3. Number of headers/line	1	1	1	N/A	N/A
4. Spray flow rate, gpm/pump	7450	6713[b,d]	6713[b]	N/A	N/A
5. Spray thermal efficiency, %	100	100	100	N/A	N/A
B. Suppression Pool Spray					
1. Number of pumps	2	2	1	N/A	N/A
2. Number of lines	2	2	1	N/A	N/A
3. Number of headers/line	1	1	1	N/A	N/A
4. Spray flow rate, gpm/pump	450	353[b]	353[b]	N/A	N/A
5. Spray thermal efficiency, %	100	100	100	N/A	N/A
C. Containment Cooling System					
1. Number of pumps	2	2	1	1[a]	1
2. Pump capacity, gpm/pump	7900	7067[b]	7067[b]	7067[b]	6713

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Table 6.2-2

Engineered Safety Systems Information
for Containment Response Analyses (Continued)

	Full Capacity	Value Used in Containment Analysis			
		Case A	Case B	Case C	Reduced ECCS Flow Case C
3. <u>Heat Exchangers</u> RHR system inverted U tube, single pass shell, multi pass tubes, vertical mounting					
a. Number	2	2	1	1[a]	1
b. Heat transfer area, ft^2/Unit	7641	7641	7641	7641	7641
c. Overall heat transfer coefficient, Btu/hr ft^2 °F	195(fouled) 400(clean)	195	195	195	195
d. Standby service water flow rate per exchanger, gpm	7400	7400	7400	N/A	N/A
e. RHR heat exchanger K value Btu/sec-°F	414(fouled) 849(clean)	N/A	N/A	289	f
f. Design service water temperature					
minimum, °F	32°F	95[b]	95[b]	90	f
maximum, °F	85°F				
g. Containment heat removal capability per loop, using 85°F service water and 165°F pool temperature; Btu/hr			83.23×10^6		

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Table 6.2-2

Engineered Safety Systems Information
for Containment Response Analyses (Continued)

	Full Capacity	Value Used in Containment Analysis			
		Case A	Case B	Case C	Reduced ECCS Flow Case C
D. <u>ECCS Systems</u>					
1. High pressure core spray (HPCS)					
a. Number of pumps	1	1	1	1[a]	1
b. Number of lines	1	1	1	1[a]	1
c. Flow rate, gpm	6350	6250	6250	6250[a]	6250
2. Low pressure core spray (LPCS)					
a. Number of pumps	1	1	0	0[a]	0
b. Number of lines	1	1	0	0[a]	0
c. Flow rate, gpm	6350	6250	0	0[a]	0
3. Low-pressure coolant injection (LPCI)					
a. Number of pumps	3	1[e]	1	1[a]	1
b. Number of lines	3	1[e]	1	1[a]	1
c. Flow rate, gpm 1 pump	7450[c]	7067[b]	7067[b]	7067[a,b]	6713

Table 6.2-2

Engineered Safety Systems Information
for Containment Response Analyses (Continued)

		Full Capacity	Value Used in Containment Analysis			
			Case A	Case B	Case C	Reduced ECCS Flow Case C
4. Residual heat removal (RHR)						
a. Pump flow rate:	shell side	7450	0	0	0	0
	tube-side	7400	0	0	0	0
b. Source of cooling water			Standby service water			
E. Automatic Depressurization System						
1. Total number of safety/relief valves		18[a]				
2. Number actuated on ADS		7[a]				

[a] No change due to uprate. Reference 6.2-35

[b] Represents conservative value used in analysis.

[c] Increase to 7900 gpm with zero differential pressure between RPV and wetwell.

[d] Only 2 of 3 LPCI pumps available for spray, and only after 600 seconds.

[e] Three LPCI pumps available; 2 pumps directed to drywell sprays after 600 seconds, with third pump continuing in LPCI mode.

[f] SW temperature is 85°F for 10 hours then 90°F thereafter; RHR heat exchanger K value varies from 284.5 to 288.8 Btu/sec-°F with suppression pool temperature.

Table 6.2-3

Accident Assumptions and Initial
Conditions for Recirculation Line Break

A. Effective accident break area (total), ft^2	3.106/3.189[d]
B. Components of effective break area:	
1. Recirculation line suction nozzle area, ft^2	2.508[a]
2. RWCU cross tie line ft^2	0.078[a]
3. Jet pump nozzles, ft^2	0.520[a]
C. Break area/vent area ratio	0.0105/0.0103[d]
D. Primary system energy distribution[b]	
1. Steam and liquid energy, 10^6 Btu	414/361[d]
2. Sensible energy, 10^6 Btu	
a. Reactor vessel	106.1/220[d]
b. Reactor internals (less core)	58.6[e]
c. Primary system piping	34.6[e]
d. Fuel	(c)
E. Assumptions used in pressure transient analysis	
1. Feedwater flow coastdown time	39.6
2. MSIV closure time (sec)	3.5/3.0[d]
3. Scram time (sec)	< 1[a]
4. Liquid carryover, %	100[a]
5. Turbine throttle valve closure (sec)	0.2

[a] No change due to uprate.
[b] All energy values except fuel are based on a 32°F datum.
[c] Fuel energy is based on a 285°F datum.
[d] Second value represents conservative value used in analysis.
[e] Reactor vessel sensible energy includes reactor internals (less core) and primary system piping.

Table 6.2-4

Initial Conditions Employed
in Containment Response Analyses

		Original Rated Power Cases	Uprated Power	Reduced ECCS Flow
A.	Reactor coolant system (at 105% of rated steam flow and at normal liquid levels)			
1.	Reactor power level, MWt	3462	3702	3556
2.	Average coolant pressure, psig	1020	1020	1020
	Peak coolant pressure, psia	1055	1055	1055
3.	Average coolant temperature, °F	547	551	551
4.	Mass of reactor coolant system liquid, lb	676,700	634,300	634,300
5.	Mass of reactor coolant system steam, lb	24,900	24,740	24,740
6.	Volume of water in vessel,[a] ft^3	12,743	13,282	13,282
7.	Volume of steam in vessel,[b] ft^3	10,167	10,397	10,397
8.	Volume of water in recirculation loops, ft^3	670	(a)	(a)
9a.	Volume of water in feedwater line,[c] ft^3	543		
9b.	Mass of water in feedwater line, lb		693,034	693,034
10.	Volume of water in miscellaneous lines,[c] ft^3	121	(a)	(a)
11.	Total reactor coolant volume, ft^3	23,580	23,679	23,679
12.	Stored water			
	a. Condensate storage tanks, gal (min)	135,000	N/A	N/A
	b. Fuel storage pool, gal	350,000	N/A	N/A

Table 6.2-4

Initial Conditions Employed
in Containment Response Analyses (Continued)

	Original Rated Power Cases	Uprated Power	Reduced ECCS Flow
	Drywell/ Suppression Chamber	Drywell/ Suppression Chamber	Drywell/ Suppression Chamber
B. Containment			
1. Pressure, psig	0.7/0.7	2.0/2.0	2.0/2.0
2. Inside temperature, °F	135/90	135/90	150/90
3. Outside temperature, °F	NA/NA	NA/NA	NA/NA
4. Relative humidity, %	50/100	50/100	20/100
5. Service water temperature, °F	95/95	90/90	(d)/(d)
6. Water volume, ft^3	NA/ 107,850	NA/ 107,850	NA/ 107,850
7. Vent submergence, ft	NA/12	NA/12	NA/12

[a] Item 6 includes items 8 and 10.
[b] Item 7 includes the main steam lines up to the inboard MSIV.
[c] Up to inboard isolation valve.
[d] 85°F for 10 hours then 90°F thereafter

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Table 6.2-5

Summary of Accident Results for Containment Response to Limiting Line Breaks

	Original Rated Power		Uprated Power	Reduced ECCS Flow
Accident Parameters	Recirculation Line Break[a]	Steam Line Break[b]	Recirculation Line Break	Recirculation Line Break
1. Peak drywell pressure, psig	34.69	34.0	37.4[c,d]	35.3[c]
2. Peak drywell diaphragm floor differential pressure, psid	19.39	19.1	21.7	(f)
3. Time (S) of Peak Pressures, Sec.	19.0	12.0	11.9	(g)
4. Peak drywell temperature, °F	280.2	328	283[c]	281[c]
5. Peak suppression chamber pressure, psig	27.3		31.3	30.3
6. Time of peak suppression chamber pressure, sec.	55	55	139	(g)
7. Peak suppression pool temperature during blowdown, °F (~100 sec.)	140	140	146	148.3
8. Peak suppression pool temperature, long term, °F	220	220	204.5	203.8
9. Calculated drywell margin, %[e]	22.9	24.5	16.9	(f)
10. Calculated suppression chamber margin, %[e]	38.6	38.0	30.4	24.6
11. Calculated deck differential pressure margin, %	22.44	23.6	13.2	(f)
12. Energy released to containment at time of peak pressure, 10^6 Btu	260	204	174	(f)
13. Energy absorbed by passive heat sinks at time of peak pressure, 10^6 Btu	0	0	0	0

Table 6.2-5

Summary of Accident Results for Containment Response to Limiting Line Breaks (Continued)

[a] See Figures 6.2-3 and 6.2-7 for plots of pressures versus time and Figures 6.2-4 and 6.2-9 for plots of temperature versus time.

[b] See Figures 6.2-15 and 6.2-16 for plots of pressure and temperature versus time respectively.

[c] For initial containment pressure of 2.0 psig.

[d] The value of P_a to be used for 10 CFR 50 Appendix J testing was conservatively chosen to be 38 psig.

[e] $$\frac{\text{(Design Pressure - Maximum Calculated Pressure)}}{\text{Design Pressure}}$$

[f] Parameter determined in short-term containment analysis (Reference 6.2-35) and not updated based on the long term analysis presented in Reference 6.2-42.

[g] Values are proprietary. See Reference 6.2-42.

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Table 6.2-6

Loss-of-Coolant Accident Long-Term Primary Containment Response Summary

	Case		LPCI and LPCS Pumps	Service Water Pumps	Containment Spray (gal/min)	HPCS (gal/min)	LPCI and LPCS (gal/min)	Peak Pool Temp (°F)	Secondary Peak Pressure (psig)
A	Original rated power 3462 MWt								
		Before 600 seconds	3/1	3	0	6250	21,200/6250	180	7.3
		After 600 seconds	3/1	3	14,134	6250	7067/6250		
B	Original rated power 3462 MWt								
		Before 600 seconds	2/0	2	0	6250	14,134/0	220	13.5
		After 600 seconds	1/0	2	7067	6250	7067/0		
C	Original rated power 3462 MWt								
		Before 600 seconds	2/0	2	0	6250	14,134/0	220	18.3
		After 600 seconds	1/0	2	0	6250	7067/0		
C	Uprated power 3702 MWt								
		Before 600 seconds	2/0	2	0	6250	14,134/0	$\boxed{204.5}$	14.3
		After 600 seconds	1/0	2	0	6250	7067/0		

Table 6.2-6
Loss-of-Coolant Accident Long-Term
Primary Containment Response (Continued)

Case		LPCI and LPCS Pumps	Service Water Pumps	Containment Spray (gal/min)	HPCS (gal/min)	LPCI and LPCS (gal/min)	Peak Pool Temp (°F)	Secondary Peak Pressure (psig)
C	Reduced ECCS Flow 3556 MWt							
	Before 600 seconds	2/0	2	0	6250	13,426/0	203.8	15.9
	After 600 seconds	1/0	2	0	6250	6713/0		

Table 6.2-7

Energy Balance for Design Basis
Recirculation Line Break Accident

		Prior to DBA (0 sec)	Time of Peak Pressure Difference Across Drywell Deck	End of Blowdown	Time of Peak [a] Containment Pressure	Unit
1)	Reactor coolant (vessel & pipe inventory)	414.0 x 10^6	400 x 10^6	12.2 x 10^6	49.4 x 10^6/44.8 x 10^6	Btu
2)	Fuel and cladding					
	Fuel	34.5 x 10^6	32.3 x 10^6	12.3 x 10^6	4.42 x 10^6/4.0 x 10^6	Btu
	Cladding	3.05 x 10^6	3.05 x 10^6	2.99 x 10^6	1.07 x 10^6/0.972 x 10^6	Btu
3)	Core internals, also reactor coolant piping, pumps, and valves	91.2 x 10^6	91.2 x 10^6	91.2 x 10^6	34.0 x 10^6/57.4 x 10^6	Btu
4)	Reactor vessel metal	107 x 10^6	107 x 10^6	107 x 10^6	40 x 10^6/66.6 x 10^6	Btu
5)	Reactor coolant piping, pumps, and valves	Included in item 3				
6)	Blowdown enthalpy	NA	551	NA	NA	Btu/lbm
7)	Decay heat	0	0.463 x 10^6	8.8 x 10^6	1020 x 10^6/222 x 10^6	Btu
8)	Metal-water reaction heat	0	0	0.01 x 10^6	0.471 x 10^6/0.471 x 10^6	Btu
9)	Drywell structures	0	0	0	0	
10)	Drywell air	1.3 x 10^6	1.6 x 10^6	0	1.61 x 10^6/1.41 x 10^6	
11)	Drywell steam	0.759 x 10^6	7.75 x 10^6	24.8 x 10^6	8.43 x 10^6/6.06 x 10^6	
12)	Containment air	0.951 x 10^6	0.951 x 10^6	2.35 x 10^6	1.13 x 10^6/1.24 x 10^6	
13)	Containment steam	0.365 x 10^6	0.365 x 10^6	1.18 x 10^6	6.04 x 10^6/2.9 x 10^6	
14)	Suppression pool water	639 x 10^6	629 x 10^6	1040 x 10^6	1450 x 10^6/1200 x 10^6	
15)	Heat transferred by heat exchangers	0	0	0	818 x 10^6/289 x 10^6	

[a] Values given are for minimum ECCS available and for all ECCS available. The information presented in this table is based on the original design basis conditions and represents the general characteristics of the recirculation line break analysis results.

Table 6.2-8

Accident Chronology Design Basis
Recirculation Line Break Accident

	Minimum ECCS Time (sec)	
	Original Rated Power	Uprated Power
1. Vents cleared	0.776	0.709
2. Drywell reaches peak pressure	19.08	11.9
3. Maximum positive differential pressure occurs	0.749	0.600
4. ECCS initiation sequence completed	30	30
5. End of blowdown	53.24	131
6. Vessel reflooded	160	153
7. Introduction of RHR heat exchanger	600	600
8. Containment reaches peak secondary pressure	29,463	25,382

Table 6.2-9a

Reactor Blowdown Data for Recirculation Line Break

Original Rated Power

Time (sec)	Steam Flow (lb/sec)	Liquid Flow (lb/sec)	Steam Enthalpy (Btu/lb)	Liquid Enthalpy (Btu/lb)
0	0	25,690	----	550.73
10.33	0	26,020	----	555.9
19.08	0	25,570	----	548.79
19.12	3679	13,320	1190	550
25.33	3213	8,493	1200.6	502
32.02	2420	4,974	1205.4	446.68
39.05	1494	2,423	1203.13	396.1
45.02	729.2	2,003	1193.79	325.16
53.37	0	0	----	----

Table 6.2-9b

Reactor Blowdown Data for Recirculation Line Break

Uprated Power

Time (sec)	Pressure (psia)[a]	Liquid Flow (lbm)	Steam Flow (lbm)
1.01	1018	3.246E+04	0
5.04	1027	2.625E+04	0
10.23	1039	2.485E+04	31.07
15.04	919	1.161E+04	3112
20.04	774.3	1.180E+04	2404
25.04	641.1	1.076E+04	1985
30.04	533.1	8.849E+03	1759
34.42	433.9	7.179E+03	1559
49.76	205.4	1.162E+04	0
62.26	147.0	9708	0
71.63	122.0	8858	0
81.01	105.6	8306	0
90.38	88.42	7560	0
102.88	71.76	6752	0
112.26	62.71	6369	0
121.63	50.97	5976	0
131.01	42.81	741.6	0

[a] Containment codes assume saturated conditions in vessel.

Table 6.2-10

Reactor Blowdown Data for Main Steam Line Break

Time (sec)	Steam Flow (lb/sec)	Liquid Flow (lb/sec)	Steam Enthalpy (Btu/lb)	Liquid Enthalpy (Btu/lb)
0	8646	0	1190.16	----
4.3	1308	27,480	1190.45	549.66
10.43	2084	24,220	1192.72	540.93
20.43	2843	15,730	1201.0	499.0
30.12	2380	7386	1205.6	432.78
40.21	1110	2734	1197.45	344.32
54.65	0	0	----	----

Table 6.2-11

Core Decay Heat Following Loss-of-Coolant Accident
for Containment Analyses

Time (sec)	Original Rated Power Normalized Core Heat[a]	Uprated Power Normalized Core Heat[b]
0.0	1.0	1.0029
0.9	0.9330	0.7053
2.1	0.7662	0.5468
5.0	0.5005	0.5533
6.93	0.3850	0.4975
9.03	0.2955	0.4119
15.93	0.1491	0.2182
30.0	0.0471	0.07730
10^2	0.0381	0.03436
10^3	0.0223	0.01956
10^4	0.0119	0.01012
10^5	0.00668	0.00546
10^6	0.00267	
3×10^6	0.00190	

[a] A normalized power level of 3462 MWt was used for analyses of original rated power and includes fuel relaxation energy.

[b] A normalized power level of 3702 MWt was used for analyses at uprated power. Uprated power case includes metal water reaction and fuel relaxation energy. The measurement uncertainty recapture project did not change the results obtained from the Uprated Power Normalized Core Heat.

Table 6.2-12

Secondary Containment Design and Performance Data

I. Secondary Containment Design

A. Free volume:

$3.5 \times 10^6\ ft^3$; the entire secondary containment is considered as one volume.

B. Pressure

1. Normal operation:

Vacuum greater than or equal to 0.25 in. of vacuum water gauge as indicated at the reactor building el. 572 ft

2. Postaccident:

Vacuum greater than or equal to 0.25 in. of vacuum water gauge on all building surfaces

C. Infiltration rate during postaccident period:

100% of free volume in a 24-hr period.

D. Exhaust fans (SGT system):

Two independent and redundant filter trains each with two full capacity exhaust fans (see Section 6.5.1)

E. The secondary containment model after a design basis LOCA is discussed in Section 6.2.3.3.1.

Table 6.2-14

Containment Penetrations Subject to Type B Tests

Penetration Number	Type Service	Comments
I. Electrical Penetrations		
X-100 A, B, C, and D	Neutron monitoring	Electrical penetrations are provided with double seals and are separately testable. The test taps and seals are located such that tests of the primary can be conducted without entry into or pressurization of containment
X-101 A, B, C, and D	Control rod position indicator	
X-102 A and B	Thermocouple and RTD	
X-103 A, B, C, and D	Medium voltage power	
X-104 A, B, C, and D	Low voltage power	
X-105 A, B, C, and D	Control and indication	
X-106 C and D	neutron monitoring	
X-107 A and B	Low voltage power control and indication	
II. Personnel And Equipment Access Penetrations		
X-15	Equipment hatch	Separately testable without pressurization of the primary containment.
X-16	Personnel access lock	
X-28	CRD removal hatch	
X-51	Suppression chamber access hatch	
X-1A through 1H	Inspection ports	
X27-A through 27F	TIP drive flanges	
N/A	Drywell head	
X-23	EDR-V-18	Inboard flange
X-24	FDR-V-15	Inboard flange
X-77Aa	RRC-V-19	Inboard & outboard flanges
	RRC-V-20	Inboard flange
X-77Ac	PSR-V-X77A/1	Inboard & outboard flanges
	PSR-V-X77A/2	Inboard flange
X-77Ad	PSR-V-X77A/3	Inboard & outboard flanges
	PSR-V-X77A/4	Inboard flange

Table 6.2-14

Containment Penetrations Subject to Type B Tests
(continued)

Penetration Number	Type Service	Comments
II. Personnel And Equipment Access Penetrations (continued)		
X-3	CEP-V-2A	Inboard flange
X-53	CSP-V-2	Inboard flange
X-66	CSP-V-4	Inboard flanges
	CSP-V-5	
X-67	CSP-V-4A	Inboard flanges
	CSP-V-6	
X-119	CSP-V-9	Inboard flange

Table 6.2-16

Primary Containment Isolation Valves

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
CRD 185 insert lines	9	4.6-5	55	B	--	--	--	--	--		--	--	--	--	--	--	--	--	--	--	--	--	Yes	5	4, 48a
CRD 185 withdrawal lines	10	4.6-5	55	B	--	--	--	--	--		--	--	--	--	--	--	--	--	--	--	--	--	Yes	5	4, 48a
Air line for maintenance	93	6.2-55	56	B	--	Pipe cap	I	--	--	--	--	--	O/C	LC	--	2	--	--	No	A	Cap	SB	No	5	54
All inst lines from pri cont	--	--	56	B	--	EF check	O	Spring	EF			O	O	O	--	1/1.5	--	--	--	--	Vlv	RB	No	5	53
All inst lines from pri cont	--	--	56	B	--	Globe	O	Manual	Manual	--	--	O	O	O	--	1/1.5	--	--	--	--	Vlv	RB	No	5	
All inst lines from RPV	--	--	55	A	--	EF check	O	Spring	EF	--	--	O	O	O	--	.75/1	--	--	--	--	Vlv	RB	No	5	27
All inst lines from RPV	--	--	55	A	--	Globe	O	Manual	Manual	--	--	O	O	O	--	.75/1	--	--	--	--	Vlv	--	No	5	
Deacon soltn return header	95	6.2-59	56	B	--	Pipe cap	O	--	--	--	--	C	C	C	--	.75	--	--	No	W	Cap	RB	No	4	
Deacon soltn supply header	94	6.2-59	56	B	--	Pipe cap	O	--	--	--	--	C	C	C	--	.75	--	--	No	W	Cap	RB	No	4	
Air line WW-DW vac RVs	82e	6.2-41	56	B	CAS-V-730	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	5	No	A	Vlv	RB	No	5	44, 54
Air line WW-DW vac RVs	82e	6.2-53	56	B	CAS-VX-82e	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	--	No	A	Vlv	RB	No	5	44, 54
DW vent ex	3	6.2-45	56	B	CEP-V-1A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	12	No	A	Vlv	RB	No	2	56
DW vent ex	3	6.2-45	56	B	CEP-V-1B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	12	No	A	Vlv	RB	No	5	56
DW vent ex	3	6.2-45	56	B	CEP-V-2A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	8	No	A	Vlv	RB	No	2	56
DW vent ex	3	6.2-45	56	B	CEP-V-2B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	8	No	A	Vlv	RB	No	5	56
WW vent ex	67	6.2-45	56	B	CEP-V-3A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	12	Yes	A	Vlv	RB	No	2	56
RB to WW vac bkrs	67	6.2-45	56	B	CEP-V-3B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	12	No	A	Vlv	RB	No	5	56
WW vent ex	67	6.2-45	56	B	CEP-V-4A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	10	No	A	Vlv	RB	No	2	56
RB to WW vac bkrs	67	6.2-45	56	B	CEP-V-4B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	10	No	A	Vlv	RB	No	5	56
CIA for SRV accum	56	6.2-38	56	B	CIA-V-20	MO globe	I	ac	ac	41	RM	O	O	O	As is	.75	No	10	No	A	Vlv	RB	Yes	5	56, 52
CIA for SRV accum	56	6.2-38	56	B	CIA-V-21	Check	I	Process	Process	--	--	C	C	C	--	.75			No	A	Vlv	RB	Yes	5	52
CIA line A for ADS accum	89B	6.2-38	56	B	CIA-V-30A	MO globe	I	ac	ac	42	RM	O	O	O	As is	.5	No	15	No	A	Vlv	RB	No	5	56

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
CIA line B for ADS accum	91	6.2-38	56	B	CIA-V-30B	MO globe	I	ac	ac	42	RM	O	O	O	As is	.5	No	15	No	A	Vlv	RB	No	5	56
CIA line A for ADS accum	89B	6.2-38	56	B	CIA-V-31A	Check	I	Process	Process	--	--	C	C	C	--	.5	--	--	No	A	Vlv	RB	No	5	
CIA line B for ADS accum	91	6.2-38	56	B	CIA-V-31B	Check	I	Process	Process	--	--	C	C	C	--	.5	--	--	No	A	Vlv	RB	No	5	
DW vent supply	53	6.2-37	56	B	CSP-V-1	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	4	No	A	Vlv	RB	Yes	2	56, 52
RB to WW vac bkrs	119	6.2-52	56	B	CSP-V-10	PC check	O	Process	Process	--	RM	C	C	C	--	24	--	4	Yes	A	Vlv	RB	No	3	26, 56
DW vent supply	53	6.2-37	56	B	CSP-V-2	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	1	No	A	Vlv	RB	Yes	2	56, 52
WW vent supply	66	6.2-37	56	B	CSP-V-3	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	17	No	A	Vlv	RB	Yes	2	56, 52
WW vent supply	66	6.2-37	56	B	CSP-V-4	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	14	No	A	Vlv	RB	Yes	2	56, 52
RB to WW vac bkrs	66	6.2-52	56	B	CSP-V-5	AO butfy	O	Spring	Air	40	RM	C	C	C	O	24	No	7	Yes	A	Vlv	RB	No	C	56
RB to WW vac bkrs	67	6.2-45 6.2-52	56	B	CSP-V-6	AO butfy	O	Spring	Air	40	RM	C	C	C	O	24	No	9	Yes	A	Vlv	RB	No	C	56
RB to WW vac bkrs	66	6.2-52	56	B	CSP-V-7	PC check	O	Process	Process	--	RM	C	C	C	--	24	--	10	Yes	A	Vlv	RB	No	3	26, 56
RB to WW vac bkrs	67	6.2-45 6.2-52	56	B	CSP-V-8	PC check	O	Process	Process	--	RM	C	C	C	--	24	--	16	Yes	A	Vlv	RB	No	3	26, 56
RB to WW vac bkrs	119	6.2-52	56	B	CSP-V-9	AO butfy	O	Spring	Air	40	RM	C	C	C	O	24	No	1	Yes	A	Vlv	RB	No	C	56
RB to WW vac bkrs and vent supply	66	6.2-37	56	B	CSP-V-93	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	4	No	A	Vlv	RW	Yes	5	52, 56
DW vent supply	53	6.2-37	56	B	CSP-V-96	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	3	No	A	Vlv	RW	Yes	5	52, 56
DW vent supply	53	6.2-37	56	B	CSP-V-97	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	5	No	A	Vlv	RB	Yes	5	52, 56
RB to WW vac bkrs and vent supply	66	6.2-37	56	B	CSP-V-98	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	6	No	A	Vlv	RB	Yes	5	52, 56
DW service line	92	6.2-47	56	B	DW-V-156	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	2	--	5	No	W	Vlv	SB	Yes	5	
DW service line	92	6.2-47	56	B	DW-V-157	Gate	I	Manual	Manual	--	--	LC	LC	LC	--	2	--	--	No	W	Vlv	SB	Yes	5	
Drywell equip drain	23	6.2-39	56	B	EDR-V-19	AO gate	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	2	No	W	Vlv	RB	No	2	56
Drywell equip drain	23	6.2-39	56	B	EDR-V-20	AO gate	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	4	No	W	Vlv	RB	No	2	56
Drywell floor drain	24	6.2-46	56	B	FDR-V-3	AO butfy	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	2	No	W	Vlv	RB	No	2	56
Drywell floor drain	24	6.2-46	56	B	FDR-V-4	AO butfy	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	3	No	W	Vlv	RB	No	2	56
SP pool cleanup return	101	6.2-50	56	B	FPC-V-149	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	41	No	W	Vlv	RB	Yes	P	48a, 56
SP pool cleanup suction	100	6.2-44	56	B	FPC-V-153	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	2	No	W	Vlv	RB	Yes	P	48a, 56

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
SP pool cleanup suction	100	6.2-44	56	B	FPC-V-154	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	7	No	W	Vlv	RB	Yes	M	48a, 56
SP pool cleanup return	101	6.2-50	56	B	FPC-V-156	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	3	No	W	Vlv	RB	Yes	M	56, 48a
HPCS suction relief	49	6.2-41	56	B	HPCS-RV-14	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	65	Yes	W	Vlv	RB	No	5	19, 18, 48a
HPCS discharge	49	6.2-41	56	B	HPCS-RV-35	Relief	O	pp	Spring	--	--	C	C	C	--	2	--	70	Yes	W	Vlv	RB	No	5	19, 18, 48a
HPCS min flow	49	6.2-41	56	B	HPCS-V-12	MO gate	O	ac	ac	38	RM	C	C	O/C	As is	4	20	53	Yes	W	Vlv	RB	No	H	56, 18, 66
HPCS suction from SP	31	6.2-49	56	B	HPCS-V-15	MO gate	O	ac	ac	46	Manual	C	C	O/C	As is	18	18	3	Yes	W	Vlv	RB	No	H	48a, 56, 18
HPCS test line	49	6.2-41	56	B	HPCS-V-23	MO globe	O	ac	ac	F,A	RM	C	C	C	As is	12	Std	6	Yes	W	Vlv	RB	No	H	56, 18, 66
HPCS to RPV	6	6.2-47	55	A	HPCS-V-4	MO gate	O	ac	ac	46	Manual	C	C	O/C	As is	12	17	9	Yes	W	Vlv	RB	No	C	56, 48b, 18
HPCS to RPV	6	6.2-47	55	A	HPCS-V-5	Check	I	Process	Process	--	--	C	C	O/C	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18
Air line for HPCS-V-5	78e	6.2-53	56	B	HPCS-V-65	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for HPCS-V-5	78e	6.2-53	56	B	HPCS-V-68	Globe	O	Manual	Manual		--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
LPCS min flow	63	6.2-41	56	B	LPCS-FCV-11	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	No	87	Yes	W	Vlv	RB	No	N	56, 66, 18
LPCS discharge RV	63	6.2-41	56	B	LPCS-RV-18	Relief	O	pp	Spring	--	--	C	C	C	--	2	--	50	Yes	W	Vlv	RB	No	5	19, 18, 48a
LPCS suction RV	63	6.2-41	56	B	LPCS-RV-31	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	25	Yes	W	Vlv	RB	No	5	19, 18, 48a
LPCS pump suction	34	6.2-49	56	B	LPCS-V-1	MO gate	O	ac	ac	46	Manual	O	O	O/C	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 18
LPCS test line	63	6.2-41	56	B	LPCS-V-12	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	12	Std	4	Yes	W	Vlv	RB	No	N	18, 56, 58, 66
LPCS to RPV	8	6.2-47	55	A	LPCS-V-5	MO gate	O	ac	ac	46	Manual	C	C	O/C	As is	12	27	22	Yes	W	Vlv	RB	No	C	56,48b, 18, 58
LPCS to RPV	8	6.2-47	55	A	LPCS-V-6	Check	I	Process	Process	--	--	C	C	O/C	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 58
Air line for LPCS-V-6	78d	6.2-53	56	B	LPCS-V-66	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for LPCS-V-6	78d	6.2-53	56	B	LPCS-V-67	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
MS lines drain inboard	22	6.2-41	55	A	MS-V-16	MO gate	I	ac	ac	V,G, D,P	RM	C	C	C	As is	3	25	--	No	S	Vlv	TB	Yes	M	52, 56, 15
Hardened Containment Vent	58	6.2-60A	56	B	HCV-V-1	AO butfy	O	Air	Spring	--	RM	C	C	C	C	16	--	33	No	A,S	Vlv	RBx	Yes	2	16, 17
Hardened Containment Vent	58	6.2-60A	56	B	HCV-V-2	AO butfy	O	Air	Spring	--	RM	C	C	C	C	16	--	68	No	A,S	Vlv	RBx	Yes	2	16, 17

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
MS lines drain outboard	22	6.2-41	55	A	MS-V-19	MO gate	O	dc	dc	V,G, D,P	RM	C	C	C	As is	3	25	6	No	S	Vlv	TB	Yes	N	52, 56, 15
MS line A inboard MSIV	18A	6.2-45	55	A	MS-V-22A	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line B inboard MSIV	18B	6.2-45	55	A	MS-V-22B	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line C inboard MSIV	18C	6.2-45	55	A	MS-V-22C	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line D inboard MSIV	18D	6.2-45	55	A	MS-V-22D	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line A outboard MSIV	18A	6.2-45	55	A	MS-V-28A	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line B outboard MSIV	18B	6.2-45	55	A	MS-V-28B	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line C outboard MSIV	18C	6.2-45	55	A	MS-V-28C	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line D outboard MSIV	18D	6.2-45	55	A	MS-V-28D	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line A drain isolation	18A	6.2-45	55	A	MS-V-67A	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line B drain isolation	18B	6.2-45	55	A	MS-V-67B	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line C drain isolation	18C	6.2-45	55	A	MS-V-67C	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line D drain isolation	18D	6.2-45	55	A	MS-V-67D	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line A loop isolation	18A	6.2-45	55	A	MSLC-V-3A	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
MS line B loop isolation	18B	6.2-45	55	A	MSLC-V-3B	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
MS line C loop isolation	18C	6.2-45	55	A	MSLC-V-3C	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
MS line D loop isolation	18D	6.2-45	55	A	MSLC-V-3D	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
Decon soltn supply header	94	6.2-59	56	B	MWR-V-124	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	.75	--	--	No	W	Cap	RB	No	5	

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
Decon soltn return header	95	6.2-59	56	B	MWR-V-125	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	.75	--	--	No	W	Cap	RB	No	5	
Rad mon return (S-SR-20)	72f	6.2-54	56	B	PI-V-X72f/1	Check	I	Process	Process	--	--	O	O	C	--	1	--	--	No	A	Vlv	RB	No	5	
Rad mon return (S-SS-21)	73e	6.2-54	56	B	PI-V-X73E/1	Check	I	Process	Process	--	--	O	O	C	--	1	--	--	No	A	Vlv	RB	No	5	
Inst lines - H2 to cont	42c	9.4-8	56	B	PI-EFC-X42C	EF check	O	Spring	EF	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 to cont	78a	9.4-8	56	B	PI-EFC-X78A	EF check	O	Spring	EF	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 to cont	42c	9.4-8	56	B	PI-V-X42C	Globe	O	Manual	Manual	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	72c	9.4-8	56	B	PI-V-X72C	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	72d	9.4-8	56	B	PI-V-X72D	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	72e	9.4-8	56	B	PI-V-X72E	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	73c	9.4-8	56	B	PI-V-X73C	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	73d	9.4-8	56	B	PI-V-X73D	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 to cont	78a	9.4-8	56	B	PI-V-X78A	Globe	O	Manual	Manual	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	82c	9.4-8	56	B	PI-V-X82C	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	84b	9.4-8	56	B	PI-V-X84B	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Air line for RHR-V-50A	42d	6.2-53	56	B	PI-VX-216	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41B	54Bf	6.2-53	56	B	PI-VX-218	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41A	61f	6.2-53	56	B	PI-VX-219	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41C	62f	6.2-53	56	B	PI-VX-220	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-50B	69c	6.2-53	56	B	PI-VX-221	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Rad mon supply (S-SR-20)	85a/c	6.2-54	56	B	PI-VX-250	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon supply (S-SR-20)	85a/c	6.2-54	56	B	PI-VX-251	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon return (S-SR-20)	72f	6.2-54	56	B	PI-VX-253	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
Rad mon return (S-SR-21)	29a/c	6.2-54	56	B	PI-VX-256	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon return (S-SR-21)	29a/c	6.2-54	56	B	PI-VX-257	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon return (S-SR-21)	73e	6.2-54	56	B	PI-VX-259	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Inst lines - H2 fm cont	72c	9.4-8	56	B	PI-VX-262	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	72d	9.4-8	56	B	PI-VX-263	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	72e	9.4-8	56	B	PI-VX-264	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	82c	9.4-8	56	B	PI-VX-265	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	73c	9.4-8	56	B	PI-VX-266	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	73d	9.4-8	56	B	PI-VX-268	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	84b	9.4-8	56	B	PI-VX-269	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Air line for RHR-V-50A	42d	6.2-53	56	B	PI-VX-42d	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41B	54Bf	6.2-53	56	B	PI-VX-54Bf	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41A	61f	6.2-53	56	B	PI-VX-61f	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41C	62f	6.2-53	56	B	PI-VX-62f	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-50B	69c	6.2-53	56	B	PI-VX-69c	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
PASS DW atm	73f	6.2-57	56	B	PSR-V-X73-1	SO globe	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS DW atm	73f	6.2-57	56	B	PSR-V-X73-2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS jet pump #10	77Ac	6.2-57	55	A	PSR-V-X77A1	SO globe	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a
PASS jet pump #10	77Ac	6.2-57	55	A	PSR-V-X77A2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a
PASS jet pump #20	77Ad	6.2-57	55	A	PSR-V-X77A3	SO globe	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a
PASS jet pump #20	77Ad	6.2-57	55	A	PSR-V-X77A4	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
PASS DW atm	80b	6.2-57	56	B	PSR-V-X80-1	SO globe	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS DW atm	80b	6.2-57	56	B	PSR-V-X80-2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS SP return	82d	6.2-58	56	B	PSR-V-X82-1	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 48a 56
PASS SP return	82d	6.2-58	56	B	PSR-V-X82-2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 48a
PASS WW atm return	82f	6.2-58	56	B	PSR-V-X82-7	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm return	82f	6.2-58	56	B	PSR-V-X82-8	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	83a	6.2-58	56	B	PSR-V-X83-1	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	83a	6.2-58	56	B	PSR-V-X83-2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	84f	6.2-58	56	B	PSR-V-X84-1	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	84f	6.2-58	56	B	PSR-V-X84-2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS line SP	88	6.2-58	56	B	PSR-V-X88-1	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	48a, 50, 56, 64
PASS line SP	88	6.2-58	56	B	PSR-V-X88-2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 64, 48a
RCC inlet header	5	6.2-55	56	B	RCC-V-104	MO gate	O	ac	ac	F,A	--	O	O	C	As is	10	60	5	No	W	Vlv	RB	Yes	4	56
RCC outlet header	46	6.2-50	56	B	RCC-V-21	MO gate	O	ac	ac	F,A	--	O	O	C	As is	10	60	3	No	W	Vlv	RB	No	4	56
RCC outlet header	46	6.2-50	56	B	RCC-V-40	MO gate	I	ac	ac	F,A	--	O	O	C	As is	10	60	--	No	W	Vlv	RB	No	4	56
RCC outlet header	46	6.2-50	56	B	RCC-V-219	Check	I	Process	Process	--	--	C	C	C	--	0.5	--	--	No	W	Vlv	RB	No	3	
RCC inlet header	5	6.2-55	56	B	RCC-V-5	MO gate	O	ac	ac	F,A	--	O	O	C	As is	10	60	3	No	W	Vlv	RB	Yes	4	56
RPV head spray	2	6.2-40	55	A	RCIC-V-13	MO gate	O	dc	dc	34	RM	C	O/C	O/C	As is	6	15	21	No	W	Vlv	RB	No	C	56, 48b, 18
Air line - spare	54Aa	6.2-53	56	B	RCIC-V-184	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	W	Vlv	RB	No	5	
RCIC min flow	65	6.2-43	56	B	RCIC-V-19	MO globe	O	dc	dc	33	RM	C	C	O/C	As is	2	22	7	No	W	Vlv	RB	No	5	22, 56, 18, 66

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
RCIC vac pump dis	64	6.2-52	56	B	RCIC-V-28	Check	O	Process	Process	--	--	C	O	O/C	--	1.5	--	5	No	W	Vlv	RB	No	5	18, 66
RCIC suct from SP	33	6.2-49	56	B	RCIC-V-31	MO gate	O	dc	dc	32	RM	C	O	O/C	As is	8	No	2	No	W	Vlv	RB	No	N	48a, 56, 18
RCIC turb ex and ex vacuum breaker	4/116	6.2-58	56	B	RCIC-V-40	Check	O	Process	Process	--	--	O	C	O/C	--	10	--	17	No	S	Vlv	RB	No	3	49
RCIC turb steam supply	21/45	6.2-40	55	A	RCIC-V-63	MO gate	I	ac	ac	K	RM	O	O/C	O/C	As is	10	16	--	Yes	S	Vlv	RB	Yes	M	51, 56, 52
RHR cond mode steam supply	21	6.2-40	55	A	RCIC-V-64	MO gate	O	Manual	Manual	--	--	LC	LC	LC	As is	10	--	2	Yes	S	Vlv	RB	No	1	39
RPV head spray	2	6.2-40	55	A	RCIC-V-66	Check	I	Process	Process	--	--	C	O	O/C	--	6	--	--	No	W	Vlv	RB	No	3	48b, 18
RCIC turb ex and ex vacuum breaker	4/116	6.2-58	56	B	RCIC-V-68	MO gate	O	dc	dc	35	RM	O	O	O/C	As is	10	No	10	No	S	Vlv	RB	No	C	22, 56
RCIC vacuum pump dis	64	6.2-52	56	B	RCIC-V-69	MO gate	O	dc	dc	36	RM	O	O	O/C	As is	1.5	No	3	No	W	Vlv	RB	No	5	22, 56, 18, 66
Air line - spare	54Aa	6.2-53	56	B	RCIC-V-740	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
RPV head spray	2	6.2-40	55	A	RCIC-V-742	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	0.75	--	3	No	W	Vlv	RB	No	5	48b
RCIC steam supply bypass	21/45	6.2-40	55	A	RCIC-V-76	MO globe	I	ac	ac	K	RM	C	C	C	As is	1	22	--	No	S	Vlv	RB	Yes	5	56, 52
RCIC turbine steam supply	45	6.2-40	55	A	RCIC-V-8	MO gate	O	dc	dc	K	RM	O	O/C	O/C	As is	4	26	2	No	S	Vlv	RB	Yes	P	51, 56, 52
RFW line A	17A	6.2-37	55	A	RFW-V-10A	Check	I	Process	Process	--	--	O	O/C	O/C	--	24	--	--	No	W	Vlv	TB	Yes	3	16, 52, 31
RFW line B	17B	6.2-37	55	A	RFW-V-10B	Check	I	Process	Process	--	--	O	O/C	O/C	--	24	--	--	No	W	Vlv	TB	Yes	3	16, 52, 31
RFW line A	17A	6.2-37	55	A	RFW-V-32A	PC check	O	Process	Process/ spring	--	--	O	O/C	O/C	--	24	--	2	No	W	Vlv	TB	Yes	3	52, 31
RFW line B	17B	6.2-37	55	A	RFW-V-32B	PC check	O	Process	Process/ spring	--	--	O	O/C	O/C	--	24	--	2	No	W	Vlv	TB	Yes	3	52, 31
RFW line A	17A	6.2-37	55	A	RFW-V-65A	MO gate	O	ac	ac	31	Manual	O	O/C	O/C	As is	24	No	8	No	W	Vlv	TB	Yes	C	56, 52, 31
RFW line B	17B	6.2-37	55	A	RFW-V-65B	MO gate	O	ac	ac	31	Manual	O	O/C	O/C	As is	24	No	8	No	W	Vlv	TB	Yes	C	56, 52, 31
Pump min flow	47	6.2-51	56	B	RHR-FCV-64A	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	20	22	Yes	W	Vlv	RB	No	L	18, 56, 66
Pump min flow	48	6.2-51	56	B	RHR-FCV-64B	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	20	22	Yes	W	Vlv	RB	No	L	18, 56, 66

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
Pump min flow	26	6.2-41	56	B	RHR-FCV-64C	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	20	30	Yes	W	Vlv	RB	No	L	18, 56, 66
Heat exch thermal RV	117	6.2-39	56	B	RHR-RV-1A	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	188	No	W	Vlv	RB	No	5	18, 19, 48a
Heat exch thermal RV	118	6.2-39	56	B	RHR-RV-1B	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	189	No	W	Vlv	RB	No	5	18, 19, 48a
Discharge header RV	47	6.2-51	56	B	RHR-RV-25A	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	33	Yes	W	Vlv	RB	No	5	18, 19, 48a
Discharge header RV	48	6.2-51	56	B	RHR-RV-25B	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	30	Yes	W	Vlv	RB	No	5	18, 19, 48a
Discharge header RV	26	6.2-41	56	B	RHR-RV-25C	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	30	Yes	W	Vlv	RB	No	5	18, 19, 48a
Flush line RV	118	6.2-39	56	B	RHR-RV-30	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	34	No	W	Vlv	RB	No	5	18, 19, 48a
Pump A and B suction RV	48	6.2-51	56	B	RHR-RV-5	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	20	Yes	W	Vlv	RB	No	5	18, 19, 48a
Pump A suction RV	47	6.2-51	56	B	RHR-RV-88A	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	30	Yes	W	Vlv	RB	No	5	18, 48a
Pump B suction RV	48	6.2-51	56	B	RHR-RV-88B	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	30	Yes	W	Vlv	RB	No	5	18, 48a
Pump C suction RV	26	6.2-41	56	B	RHR-RV-88C	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	37	Yes	W	Vlv	RB	No	5	18, 19, 48a
Heat exch cond	47	6.2-51	56	B	RHR-V-11A	MO gate	O	Manual	Manual	--	--	LC	LC	LC	As is	4	--	18	Yes	W	Vlv	RB	No	1	18, 39, 66
Heat exch cond	48	6.2-51	56	B	RHR-V-11B	MO gate	O	Manual	Manual	--	--	LC	LC	LC	As is	4	--	No	Yes	W	Vlv	RB	No	1	18, 39, 66
FDR system intertie	47	6.2-51	56	B	RHR-V-120	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	3	--	7	No	W	Vlv	RB	No	1	54, 18, 66
FDR system intertie	47	6.2-51	56	B	RHR-V-121	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	3	--	6	No	W	Vlv	RB	No	1	54, 18, 66
SDC return A	19A	6.2-48	55	A	RHR-V-123A	MO gate	I	ac	ac	F,L	RM	C	O/C	--	As is	1	15	--	Yes	W	Vlv	RB	No	5	56, 48b, 18
SDC return B	19B	6.2-48	55	A	RHR-V-123B	MO gate	I	ac	ac	F,L	RM	C	O/C	--	As is	1	15	--	Yes	W	Vlv	RB	No	5	56, 48b, 18
RHR cond pot drain A	117	6.2-39	56	B	RHR-V-124A	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	11	Yes	W	Vlv	RB	No	5	38, 18, 66
RHR cond pot drain A	117	6.2-39	56	B	RHR-V-124B	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	12	Yes	W	Vlv	RB	No	5	39, 18, 66

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
RHR cond pot drain B	118	6.2-39	56	B	RHR-V-125A	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	17	Yes	W	Vlv	RB	No	5	39, 18, 66
RHR cond pot drain B	118	6.2-39	56	B	RHR-V-125B	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	14	Yes	W	Vlv	RB	No	5	39, 18, 66
CAC drain A	117	6.2-39	56	B	RHR-V-134A	MO globe	O	Manual	Manual	--	--	LC	LC	LC	LC	2	No	44	No	W	Vlv	RB	No	5	18, 65, 66
CAC drain B	118	6.2-39	56	B	RHR-V-134B	MO globe	O	Manual	Manual	--	--	LC	LC	LC	LC	2	No	44	No	W	Vlv	RB	No	5	18, 65, 66
Drywell spray A	11A	6.2-42	56	B	RHR-V-16A	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	16	Std	26	Yes	W	Vlv	RB	No	I	56, 18
Drywell spray B	11B	6.2-42	56	B	RHR-V-16B	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	16	Std	12	Yes	W	Vlv	RB	No	I	56, 18
Drywell spray A	11A	6.2-42	56	B	RHR-V-17A	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	16	Std	24	Yes	W	Vlv	RB	No	I	56, 18
Drywell spray B	11B	6.2-42	56	B	RHR-V-17B	MO gate	O	ac	ac	46	RM	C	O	O/C	As is	16	Std	2	Yes	W	Vlv	RB	No	I	56, 18
SDC	20	6.2-46	55	A	RHR-V-209	Check	I	Process	Process	--	--	C	C	--	--	.75	--	--	No	W	Vlv	RB	No	5	48b, 18
RHR test line C	26	6.2-41	56	B	RHR-V-21	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	18	Std	34	Yes	W	Vlv	RB	No	L	18, 56, 60, 66
RPV head spray	2	6.2-40	55	A	RHR-V-23	MO globe	O	ac	dc	L, U, M, R	RM	C	O/C	C	As is	6	Std	28	Yes	W	Vlv	RB	No	C	56, 57, 59,48b, 18
RHR test A	47	6.2-51	56	B	RHR-V-24A	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	18	Std	12	Yes	W	Vlv	RB	No	N	2, 18, 66, 28, 56
RHR test B	48	6.2-51	56	B	RHR-V-24B	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	18	Std	12	Yes	W	Vlv	RB	No	N	2, 18, 66, 56, 57, 59
SP spray A	25A	6.2-43	56	B	RHR-V-27A	MO gate	O	ac	ac	F,V	RM	C	C	O/C	As is	6	36	5	Yes	W	Vlv	RB	No	N	2, 18, 56
SP spray B	25B	6.2-43	56	B	RHR-V-27B	MO gate	O	ac	ac	F,V	RM	C	C	O/C	As is	6	36	6	Yes	W	Vlv	RB	No	N	2, 18, 56
LPCI A	12A	6.2-47	55	A	RHR-V-41A	Check	I	Process	Process	--	--	C	C	O/C	--	14	--	--	Yes	W	Vlv	RB	No	3	3, 28, 48b, 18
LPCI B	12B	6.2-47	55	A	RHR-V-41B	Check	I	Process	Process	--	--	C	C	O/C	--	14	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 57, 59
LPCI C	12C	6.2-47	55	A	RHR-V-41C	Check	I	Process	Process	--	--	C	C	O/C	--	14	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 60

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
LPCI A	12A	6.2-47	55	A	RHR-V-42A	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	14	27	21	Yes	W	Vlv	RB	No	C	48b,56, 18, 28
LPCI B	12B	6.2-47	55	A	RHR-V-42B	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	14	27	20	Yes	W	Vlv	RB	No	C	48b, 56, 18, 57, 59
LPCI C	12C	6.2-47	55	A	RHR-V-42C	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	14	27	20	Yes	W	Vlv	RB	No	C	48b,56, 18, 60
RHR SP suction A	35	6.2-49	56	B	RHR-V-4A	MO gate	O	ac	ac	46	RM	O	O/C	O	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 61, 18, 20
RHR SP suction B	32	6.2-49	56	B	RHR-V-4B	MO gate	O	ac	ac	46	RM	O	O/C	O	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 61, 18, 20
RHR SP suction C	36	6.2-49	56	B	RHR-V-4C	MO gate	O	ac	ac	46	RM	O	O/C	O	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 61, 18, 20
SDC return A	19A	6.2-48	55	A	RHR-V-50A	Check	I	Process	Process	--	--	C	O	--	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 28
SDC return B	19B	6.2-48	55	A	RHR-V-50B	Check	I	Process	Process	--	--	C	O	--	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 57, 59
SDC return A	19A	6.2-48	55	A	RHR-V-53A	MO gate	O	ac	ac	M, L, U, R	RM	C	O	--	As is	12	40	5	Yes	W	Vlv	RB	No	C	56,48b, 18, 28
SDC return B	19B	6.2-48	55	A	RHR-V-53B	MO gate	O	ac	ac	M, L, U, R	RM	C	O	--	As is	12	40	5	Yes	W	Vlv	RB	No	C	56, 57, 59, 48b, 18
Heat exch vent	117	6.2-51	56	B	RHR-V-73A	MO globe	O	ac	ac	39	RM	C	O/C	C	As is	2	No	175	No	A/W	Vlv	RB	No	5	18, 56, 66
Heat exch vent	118	6.2-51	56	B	RHR-V-73B	MO globe	O	ac	ac	39	Manual	C	O/C	C	As is	2	No	190	No	A/W	Vlv	RB	No	5	18, 56, 66
SDC	20	6.2-46	55	A	RHR-V-8	MO gate	O	dc	dc	L, U, M, R	RM	C	O	--	As is	20	40	14	Yes	W	Vlv	RB	No	N	56, 20, 48b, 61, 18
SDC	20	6.2-46	55	A	RHR-V-9	MO gate	I	ac	ac	L, U, M, R	RM	C	O	--	As is	20	40	--	Yes	W	Vlv	RB	No	N	48b, 56, 61, 18, 20
RRC pump A seal	43A	6.2-38	56	B	RRC-V-13A	Check	I	Process	Process	--	--	O	O	O	--	.75	No	--	No	W	Vlv	RB	No	5	--
RRC pump B seal	43B	6.2-38	56	B	RRC-V-13B	Check	I	Process	Process	--	--	O	O	O	--	.75	No	--	No	W	Vlv	RB	No	5	--

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
RRC pump A seal	43A	6.2-38	56	B	RRC-V-16A	MO gate	O	ac	ac	45	RM	O	O	O	As is	.75	No	2	No	W	Vlv	RB	No	5	56
RRC pump B seal	43B	6.2-38	56	B	RRC-V-16B	MO gate	O	ac	ac	45	RM	O	O	O	As is	.75	No	2	No	W	Vlv	RB	No	5	56
RRC sample line	77Aa	6.2-39	55	A	RRC-V-19	SO globe	I	ac	Spring	A,C	RM	O	C	C/O	C	.75	5	--	No	W	Vlv	TB	Yes	5	56, 48a
RRC sample line	77Aa	6.2-39	55	A	RRC-V-20	SO globe	O	ac	Spring	A,C	RM	O	C	C/O	C	.75	5	--	No	W	Vlv	TB	Yes	5	56, 48a
RWCU from reactor	14	6.2-46	55	A	RWCU-V-1	MO gate	I	ac	ac	A,J,E	RM	O	O	C	As is	6	16.25	--	No	W	Vlv	RW	Yes	M	51, 48a, 56
RWCU from reactor	14	6.2-46	55	A	RWCU-V-4	MO gate	O	dc	dc	A,J,E, Y, W	RM	O	O	C	As is	6	16.25	4	No	W	Vlv	RW	Yes	2	51, 48a, 56
RFW line A	17A/ 17B	6.2-37	55	A	RWCU-V-40	MO gate	O	ac	ac	47	Manual	O	O	O/C	As is	6	No	24	No	W	Vlv	TB	Yes	C	56, 52
Air line for maintenance	93	6.2-55	56	B	SA-V-109	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	2	--	1	No	A	Cap	SB	No	5	54
SLC to RPV	13	6.2-48	55	A	SLC-V-4A	Explosive	O	--	--	--	--	C	C	C	--	1.5	--	136	No	W	Vlv	RB	No	5	21
SLC to RPV	13	6.2-48	55	A	SLC-V-4B	Explosive	O	--	--	--	--	C	C	C	--	1.5	--	136	No	W	Vlv	RB	No	5	21
SLC to RPV	13	6.2-48	55	A	SLC-V-7	Check	I	Process	Process		--	C	C	C	--	1.5	--	--	No	W	Vlv	RB	No	5	
TIP lines	27A	--	56	B	TIP-V-1	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27D	--	56	B	TIP-V-10	Exp shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27E	--	56	B	TIP-V-11	Exp shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27F	--	56	B	TIP-V-15	SO globe	O	ac	Spring	A,F	--	O	O	C	C	1	--	2	No	A	Vlv	RB	Yes	5	52, 56
TIP lines	27B	--	56	B	TIP-V-2	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27C	--	56	B	TIP-V-3	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27D	--	56	B	TIP-V-4	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27E	--	56	B	TIP-V-5	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27F	--	56	B	TIP-V-6	Check	I	Process	Process	--	--	O	C	C	--	.5	--	1	No	A	Vlv	RB	Yes	5	52
TIP lines	27A	--	56	B	TIP-V-7	Exp Shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27B	--	56	B	TIP-V-8	Exp Shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27C	--	56	B	TIP-V-9	Exp Shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29

Table 6.2-16

Primary Containment Isolation Valves (Continued)

ISOLATION SIGNAL CODES[a]

Signal	Description
A[b]	Reactor vessel low-low water level (Trip level 2)
C[b]	High radiation - main steam line
D[b]	Line break - main steam line (steam line tunnel high temperature, high differential temperature or steam line high flow)
E[b]	Reactor water cleanup system high differential flow or high blowdown flow
F[b]	High drywell pressure
G[b]	Low condenser vacuum
J[b]	Line break in RWCU system – area high temperature or high differential temperature
K[b]	Line break in RCIC system (RCIC area high temperature, high differential temperature, or high steam flow), [Low steam pressure or turbine exhaust diaphragm high pressure are other signals not part of PCRVICS]
L[b]	Reactor vessel low water level (Trip level 3) (A scram occurs at this level. This is the higher of the three low water level signals)
M[b]	Line break in RHR shutdown cooling (high suction flow)
P[b]	Low main steam line pressure at turbine inlet (RUN mode only)
R[b]	RHR equipment area high temperature or high differential temperature
RM	Remote manual switch located in main control room
U	High reactor vessel pressure
V[c]	Reactor vessel low-low-low water level (Trip level 1)
W	High temperature at outlet of RWCU system nonregenerative heat exchanger
Y	Standby liquid control system actuated
Z[b]	Reactor building ventilation exhaust plenum high radiation

[a] See notes 30 through 46 for isolation signals generated by the individual system process control signals or for remote-manual closure based on information available to the operators. These notes are referenced in the "isolation signal" column.

[b] These are the isolation functions of the primary containment and reactor vessel isolation control system (PCRVICS). Other functions are provided for information only.

[c] Reactor vessel low-low-low water level (Trip level 1) is an isolation function of the primary containment and reactor vessel isolation control system (PCRVICS) for Group 1 valves only.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

ABBREVIATIONS/LEGEND

Valve Type	
AO	air-operated
EHO	electrohydraulic operated
MO	motor-operated
PC	positive closing
SO	Solenoid operated

Location	
I	inside containment
O	outside containment

Power to Open/Close	
AC	ac electrical power
DC	dc electrical power
EF	excess flow
pp	process fluid overpressurization
pro	process, process flow
spr	spring

Normal Position	
C	closed
LC	locked closed
LO	locked open
O	open
SC	sealed closed (lead)

Process Fluid	
A	air
H	hydraulic fluid
S	steam
W	water

Termination Zone	
CS	condensate storage tank
RB	reactor building
RBx	reactor building external
RW	radwaste building
SB	service building
TB	turbine building

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

Type C testing is discussed in Figures 6.2-36 through 6.2-60A which shows the isolation valve arrangement. Unless otherwise noted all valves listed in Table 6.2-16 are Type C tested.

1. Main steam isolation valves require that both solenoid pilots be deenergized to close valves. Accumulator air pressure plus spring set act together to close valves when both pilots are deenergized. Voltage failure at only one pilot does not cause valve closure. The valves are designed to fully close in less than 10 sec.

2. Suppression cooling valves have interlocks that allow them to be manually reopened after automatic closure. This setup permits suppression pool spray, for high drywell pressure conditions and/or suppression water cooling. When automatic signals are not present, these valves may be opened for test or operating convenience.

3. The air test function is not used.

4. The CRD insert and withdraw lines are not subject to Type A testing since these pathways are not open to the Primary Containment atmosphere under post-DBA conditions (ANSI/ANS-56.8-1994, Section 3.2.5). These lines would always remain filled with water and provide a water seal following a design basis accident (DBA) and therefore do not represent a gaseous fission product release pathway.

   The CRD insert and withdraw lines are not subject to Type C testing, since these Primary Containment boundaries do not constitute potential Primary Containment Atmospheric pathways during and following a design basis accident (NEI 94-01, Section 6.0, and ANSI/ANS-56.8-1994, Section 3.3.1(1)).

   The above positions are in compliance with NRC Regulatory Guide 1.163.

   See Section 6.2.4.3.2.1.1.4 for additional design information.

5. Alternating current motor-operated valves required for isolation functions are powered from the ac standby power buses. Direct current operated isolation valves are powered from station batteries.

6. All motor-operated isolation valves remain in the last position upon failure of valve power. All air-operated valves close in the safest position on motive air failure.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

7. STD - The close limit is based on a standard minimum closing rate of 12 in. of nominal valve diameter per minute for gate valves and 4 in. of valve stem travel per minute for globe valves.

   No - No limiting value of full stroke closure time is specified. The close limit is based on results from testing performed in accordance with ASME/ANSI OM Part 10 Section 3 Testing Requirements.

8. Reactor building ventilation exhaust plenum high radiation signal (Z) is generated by two trip units in each safety division. This requires a trip from both units in a division (fail-safe design) to initiate isolation.

9. Primary containment and reactor vessel isolation signals (PCRVIS) are indicated by letters. Isolation signals generated by the individual system process control signals or for remote manual closure based on information available to the operator are discussed in the referenced notes in the "isolation signal" column.

10. Normal status position of valve (open or closed) is the position during normal power operation of the reactor (see Normal Position column). Valves, blind flanges, and deactivated automatic valves that are within the primary containment or other areas administratively controlled to prohibit access for reasons of personnel safety are locked, sealed, or otherwise secured in the closed position. Valves 1.5 in. and smaller connected to vents, drains, or test connections must be closed but need not be sealed.

11. The specified closure rates are as required for containment isolation or system operation, whichever is less. Reported times are in seconds.

12. All isolation valves are Seismic Category I.

13. Used to evaluate primary containment leakage which may bypass the secondary containment emergency filtration system.

14. Reported sizes are the valve nominal diameters in inches. Size indicated is containment side of relief valve when relief valve size is not equal on both sides.

15. Reactor vessel low-low-low water level (Trip level 1) is an isolation function of the primary containment and reactor vessel isolation control system (PCRVICS) for Group 1 valves only.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

16. Utilizes rupture discs downstream of the PCIVs and upstream of the secondary containment penetration to establish a closed system for compliance with GDC 56.

17. Rupture discs prevent secondary containment bypass leakage.

18. These lines connect to systems outside of the primary containment which meet the requirements for a closed system. These systems are considered an extension of the primary containment. Any external leakage out of these systems, within the Reactor Building, is processed by the SGT system.

19. Relief valve setpoint greater than 77.5 psig (1.5 times containment design pressure).

20. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-1, is connected to the condensate system with a blind flange on the other end.

21. Cannot be reshut after opening without disassembly.

22. See 6.2.4.3.2.2.1.2.

23. See 6.2.4.3.2.2.2.

24. Not Used.

25. DELETED.

26. The disc on the check valve is maintained in the close position during normal operation by means of a spring actuated lever arm and magnets embedded in the periphery of the disc. The magnetic and spring forces maintain the disc shut until the differential force to open the valve exceeds approximately 0.2 psid. The check valves have position indication lights which can alert the operators to the fact that the check valve is not fully closed. The operator can then remotely shut the valve by means of a pneumatic operator. The operating switch is spring-return to neutral so the vacuum breaker function will not be impaired.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

27. Instrument lines that penetrate primary containment conform to Regulatory Guide 1.11. The lines that connect to the reactor pressure boundary include a restricting orifice inside containment, are Seismic Category I and terminate in instruments that are Seismic Category I. The instrument lines also include manual isolation valves and excess flow check (EFC) valves. Manual and EFC valves have no active safety (containment isolation) function requirements. These penetrations will not be Type C tested since the integrity of the lines are continuously demonstrated during plant operations where subject to reactor operating pressure. In addition, all lines are subject to the Type A test pressure on a regular interval. Leaktight integrity is also verified with completion of functional and calibration surveillance activities as well as by visual inspection.

28. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-2, is connected to the condensate system with a blind flange on the other end.

29. The ball valves are Type C tested in accordance with Appendix J of 10 CFR 50. Because the shear valves have explosive squibs and require testing to destruction, they are not Type C tested. Technical Specifications surveillance requirements ensure shear valve operability.

See subsection 6.2.4.3.2.2.3.11 for a TIP system isolation evaluation against General Design Criterion 56.

30. Deleted.

31. PCRVIS is not desirable since the feedwater system, although not an ESF system, could be a significant source of makeup after a LOCA which is not concurrent with a seismic event.

Feedwater check valves on either side of the containment can provide immediate leak isolation. The feedwater block valves can, however, be remote-manually closed if there is no indication of feedwater flow.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

32. The RCIC suppression pool suction valve is normally closed and does not receive an automatic isolation signal.

    Operator action can be taken to remote-manually shut isolation valve RCIC-V-31. The system would be manually isolated on a reactor building sump high level alarm if RCIC is determined to be the source of leakage in the reactor building.

33. The RCIC minimum flow valve is open only between the time of system initiation and the time at which the system flow to the RPV exceeds the pump minimum flow requirement. The valve is shut at all other times. Valve RCIC-V-19 auto closes when the turbine throttle valve is closed following a turbine trip. Should a leak occur when the valve is open, it will be detected by a high level alarm in the appropriate reactor building sump.

34. The RCIC injection valve is open only during RCIC turbine operation. Injection line check valves on either side of the containment can provide immediate leak isolation. Valve RCIC-V-13 auto closes when the turbine throttle valve is closed following a turbine trip.

35. The RCIC steam exhaust valve, RCIC-V-68, is normally open at all times. Should a leak occur, it would be detected and alarmed by the RCIC room high temperature leak detection system.

36. The RCIC vacuum pump discharge valve, RCIC-V-69, is normally open at all times. The valve could be remote-manually closed by the operator upon control room indication that vacuum can no longer be maintained in the barometric condenser.

37. DELETED

38. The minimum flow valve for an ECCS pump is open whenever the pump is running and the flow in the pump discharge line is below the trip setpoint. The valve is shut at all other times. Should a leak occur when the valve is open, it will be detected by a high level alarm in the appropriate reactor building sump.

39. These valves are deactivated. The valves are shown as motor operated, however, the power leads to the motors have been disconnected and the handwheels have been chained and padlocked in the closed position.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

40. Normally closed. Signaled to open if reactor building pressure exceeds wetwell pressure by 0.5 psid (analytical limit). Valves automatically reshut when the above condition no longer exists. Operators use valve position indicator as confirmation of valve status.

41. Indication of containment instrument air main header pressure and a low pressure alarm exist in the main control room. The operator can remote-manually shut valve CIA-V-20 should the supply from the CN system or from the CAS cross-tie becomes unavailable. Isolation check valve CIA-V-21 provides immediate isolation.

42. Indication of nitrogen bottle header pressure and a low pressure alarm exist in the main control room. The operator can remote-manually shut valve CIA-V-30(A, B) should the nitrogen bottle bank pressure decrease below the alarm setpoint. Isolation check valves CIA-V-31(A, B) provide immediate isolation.

43. The TIP shear valves are remote-manually closed following control room indication of the failure of the TIP ball valves to close.

44. Normally closed. Opened only when testing wetwell-to-drywell (WW-DW) vacuum breakers. Test connection upstream of outer isolation valve is normally open. Closed during testing.

45. The isolation valve can be remote-manually closed upon indication that the CRD or the RRC pumps have tripped. Isolation check valves RRC-V-13 (A, B) provide immediate isolation.

46. These valves are the ECCS and drywell spray suction and discharge isolation valves. There are no automatic isolation signals. The valve closure requirement is indicated by a high level alarm in the appropriate reactor building sump.

47. The isolation valve can be remote-manually closed upon indication that the RWCU pumps have tripped. The reactor feedwater isolation check valves provide immediate isolation.

48a. Not subject to Type C leak testing, per Primary Containment Leakage Rate Testing Program. Prepared per Option B of 10 CFR 50 Appendix J.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

48b. The isolation valve is tested with water. The maximum allowable leakage rate is included in the Technical Specifications.

49. Isolation for the RCIC turbine exhaust vacuum breaker lines (X-116) is provided by containment isolation valves in the RCIC turbine exhaust line (X-4) and the RHR combined return line (X-47, X-48) to the suppression pool. Valves RCIC-V-110 and RCIC-V-113 serve as an extension of containment but do not function as containment isolation valves and will not require Type C testing.

50. System isolation valves are normally closed. The system is placed in operation following a LOCA for post accident sampling. Valve position indication is provided in the main control room.

51. The limiting times for valve closure are based on the pipe break isolation times used in the Environmental Equipment Qualification Program to establish the environmental profiles for qualifying safety-related equipment within the reactor building.

52. The sum of the Type C leak rate tests for the potential bypass leak paths will not exceed 0.04 percent of primary containment volume per day.

53. Instrument lines that penetrate primary containment conform to Regulatory Guide 1.11. These lines include manual isolation valves and excess flow check (EFC) valves, or solenoid-operated valves capable of remote operation from the control room. These lines are Seismic Category I and terminate at instrument racks that are Seismic Category I. Manual and EFC valves have no active safety (containment isolation) function requirements. These penetrations will not be Type C tested since the communicating lines are extensions of primary containment and the valves do not receive automatic isolation signals. In addition, all lines are subject to the Type A test on a regular interval (excluding some local pressure instruments which are over-ranged or initiate RPS actuations by Type A test pressure). Section 6.2.4.4 discusses periodic actuation testing requirements.

54. These paths are not potential secondary containment bypass leakage paths and are not required to meet the requirements for secondary containment design. The piping system outside of the outermost containment isolation valve is aligned such that leakage past these valves will be released to secondary containment and be processed by standby gas treatment.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

55. Not Used.

56. A channel check and channel calibration is required of the remote valve position indication.

57. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-3, is connected to the condensate system with a blind flange on the other end.

58. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the LPCS piping flange. The spool piece, COND-RSP-5, is connected to the condensate system with a blind flange on the other end.

59. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-6, is connected to the condensate system with a blind flange on the other end.

60. The condensate system can be used to flush LPCI C through a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange of COND-RSP-4.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

61. A blind flange is installed downstream of valves RHR-V-108 and RHR-V-109. This blind is located in the RHR pump room C and ensures that there is no by-pass leakage from the RHR pump suction line to the condensate storage tanks. The condensate system can be used to flush RHR shutdown cooling through a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on RHR-RSP-1.

62. This column provides the station blackout (SBO) criterion that was used for each primary containment isolation valve to establish whether or not the valve needed to be assessed for closure capability in the event of an extended SBO. The values provided in this column are defined as follows:

Criterion	Basis for Exclusion
1	Valve is normally locked closed during operation.
2	Valve auto closes or fails closed on loss of ac power or air.
3	Valve is a check valve.
4	Valve is in nonradioactive closed-loop systems not expected to be breached during a SBO (the valve cannot be in a line that communicates directly with the containment atmosphere).
5	Valve is less than 3 in. nominal diameter.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

Valves that did not meet one of these exclusion criteria were considered as "valves of concern." The alphabetic data provided in this column identifies how this set of valves was addressed:

Criterion	Additional Basis for Exclusion
C	Valve has an in-series check valve that will provide for isolation of the penetration.
D	Valve has an in-series valve that fails closed on an SBO.
M	Valve has an in-series valve with SBO closure capability.
I	The penetration is provided with an interlock that ensures closure of at least one of the containment isolation valves during operation.
H	Valve is required to provide for HPCS operation.
L	For the associated penetration, GDC 56 is satisfied by a single isolation valve, connected to the suppression pool with the line submerged and a high integrity closed loop system outside containment.
N	Valve is required to be closed during power operation (open for brief periods for the purpose of performing a surveillance is acceptable) and the piping outside containment being a high integrity closed loop system.
P	Valve is included in the table as being associated with a potential secondary containment bypass leakage path. It is not a primary containment isolation valve.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

63. Leakage rate not included in sum of Type B and C test.

64. These are potential secondary containment bypass leakage paths whenever the railroad bay doors are open. The valves are tested for leakage to ensure requirements for limiting secondary containment bypass leakage are satisfied.

65. Valves RHR-V-134A and RHR-V-134B have been deactivated. Blind flanges CAC-BF-3A and CAC-BF-3B provide containment pressure boundaries in the lines outboard of valves.

66. These valves are in lines that are below the minimum water level in the suppression pool and are part of closed systems outside of the primary containment. Therefore, 10 CFR 50 Appendix J Type C and hydraulic local leak rate testing is not required.

Table 6.2-17

Hydrogen Recombiner
(Historical Information Only - System Has Been Deactivated In-Place)

1.	Tag number		CAC-HR-1A & 1B
2.	Number of units		2
3.	Type		Skid-mounted package
4.	Nominal flow		200 acfm at blower
5.	Canned blower		Rotary lobe, positive displacement pump enclosed within an ASME vessel
6.	Drive		Direct (15 hp motor)
7.	Motor type		Totally enclosed fan-cooled, Class H insulation, with maximum temperature rise of 125°C above 40°C ambient
8.	Nominal pressure across blower		7 psi
9.	Scrubber		
	a.	Type	Stainless steel, ring packed tower
	b.	Water flow	10 gpm (maximum)
10.	Heater/Recombiner		
	a.	Heater type	Electric, 27 U-tube elements
	b.	Heater capacity	37 kW
	c.	Recombiner type	Catalytic
	d.	Recombiner catalyst	Houdry HSC-931, 0.5% Platinum on alumina
11.	Aftercooler		
	a.	Type	Shell and tube heat exchanger
	b.	Water flow	50 gpm (maximum)
12.	Moisture Separator		
	a.	Type	Vertical vessel with demister at top
13.	Seismic Category		I

Table 6.2-19

Assumptions and Initial Conditions for Negative Pressure Design Evaluation

A. Containment preincident conditions used for sizing internal vacuum breakers (wetwell to drywell)

		Drywell (DW)	Suppression Chamber (WW)
1.	Pressure, psig	0	0
2.	Temperature, °F	150	50
3.	Relative humidity, %	100	100

B. Containment preincident conditions used for sizing external vacuum breakers (reactor building to wetwell).

		Drywell (DW)	Suppression Chamber (WW)
1.	Pressure, psig	-1.0	-0.5
2.	Airspace temperature, °F	135	50
	Pool temperature, °F	N/A	50
3.	Relative humidity, %	100	100

Spray temperature is equivalent to suppression pool temperature.

Table 6.2-19a

Limiting Conditions for Maximum
Negative Pressure Differentials Applied
to Columbia Generating Station Specifications

				Maximum Negative Pressure Differential (psid)			
Hypothetical Event	DW-WW VBs	RB-WW VBs	DW Sprays	WW-DW	RB-WW	DW-RB	Remarks
(1) Inadvertent spray activation	7	3	NA	-	-	-	Not possible due to containment high pressure interlock
(2) Small pipe break							
liquid	7	2	1[a]	0.57	1.38	1.88	
steam	7	2	1[a]	0.55	0.61	1.11	
(3) DBA	7	2	1[a]	0.55	0.71	1.21	1 RB-WW VB failure
	7	3	2	0.67	0.81	1.31	Use of two sprays No VB failure VBs adequate
(4) Vented drywell with a small steam leak	7	3	NA	-	-	-	Included in small pipe break event (2)
(5) Normal heating and cooling cycles	7	3	NA	-	-	-	Controlled with the primary containment cooling system

[a] Drywell and wetwell sprays used in event mitigation from one RHR loop only.

Table 6.2-20

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 6-in. RCIC Line*
Steam

Time (sec)	Mass Rate (lb/sec)	Energy Rate (Btu/sec x 10^3)
0.0	398.2	474.694
3.0	398.2	474.694

* Original rated power – Reference 6.2-29.

Table 6.2-21

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 6-in. RCIC Line*
Water

Time (sec)	Mass Rate (lb/sec)	Energy Rate (Btu/sec x 10^3)
0.0	0.0	0.0
0.001	331.1	388.347
0.004	205.6	195.094
0.010	398.3	231.811
0.015	598.8	329.639
0.020	700.0	381.430
0.025	724.4	392.915
0.050	580.0	311.576
0.10	394.2	198.953
0.20	144.6	59.387
0.30	52.4	18.555
0.40	35.1	8.884
0.50	46.1	11.046
1.00	45.9	10.585
1.50	36.0	7.639
1.90	30.4	6.314

* Original rated power – Reference 6.2-30.

Table 6.2-21

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 6-in. RCIC Line*
Water (Continued)

Time (sec)	Mass Rate (lb/sec)	Energy Rate (Btu/sec x 10^3)
2.00	21.1	4.378
2.50	23.3	4.523
3.00	3.2	0.611

* Original rated power – Reference 6.2-30.

Table 6.2-22

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 24-in. Recirculation Line*
Steam

Time (sec)	Mass Rate (lb/sec x 10^3)	Energy Rate (Btu/sec x 10^6)
0.0	0.0	0.0
21.0	0.0	0.0
21.01	3.2	3.815
30.00	2.4	2.861
40.00	1.3	1.550
47.00	2.0	2.384
47.01	4.0	4.768
48.00	0.0	0.0
50.00	0.0	0.0

* Original rated power – Reference 6.2-31.

Table 6.2-23

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 24-in. Recirculation Line*
Water

Time (sec)	Mass Rate (lb/sec x 10^3)	Energy Rate (Btu/sec x 10^6)
0.00	22.72	12.393
0.00159	22.72	12.393
0.00171	34.07	18.585
1.537	34.07	18.585
1.568	27.56	15.033
2.037	27.56	15.033
2.040	25.00	13.637
21.00	25.00	13.637
21.01	11.80	6.437
30.00	7.00	3.818
40.00	3.50	1.909
45.00	3.80	2.073
47.00	3.70	2.018
47.01	0.0	0.0
50.00	0.0	0.0

* Original rated power – Reference 6.2-31.

Table 6.2-24

Nodal Volume Data
for the Case of a 6-in. RCIC Line Break and the Case of a 24-in. Recirculation Line Break*

Node Number	Description	Net Volume (ft^3)	Elevation (Bottom, ft)	Height (ft)
1	Drywell above Bulkhead Plate	4,789.5	582.6	15.98
2	Drywell below Bulkhead Plate	195,759.5	499.6	83.1

* Original rated power.

Table 6.2-25

Flow Path Data
for the Case of a 6-in. RCIC Line Break*

From Node	To Node	Flow Area (ft^2)	Inertia (L/A, ft^{-1})	Form Loss Coefficient K_F*	Form Loss Coefficient K_R**	Friction Factor f
1	2	4.926	0.4107	1.6	1.6	(See Note)
1	2	4.666	1.60	4.090	4.102	(See Note)

Note: The fanning friction factor is automatically included by an internal calculation in the computer program and is variable with reynolds number.

K_F* = $K_{Forward}$

K_R** = $K_{Reverse}$

* Original rated power.

Table 6.2-26

Flow Path Data
for the Case of a 24-in. Recirculation Line Break*

From Node	To Node	Flow Area (ft^2)	Inertia (L/A, ft^{-1})	Form Loss Coefficient K_F*	Form Loss Coefficient K_R**	Friction Factor f
2	1	4.926	0.4107	1.6	1.6	(See Note)
2	1	4.666	1.60	4.102	4.090	(See Note)

Note: The fanning friction factor is automatically included by an internal calculation in the computer program and is variable with reynolds number.

K_F* = $K_{Forward}$

K_R** = $K_{Reverse}$

* Original rated power.

Table 6.2-27

Peak Differential Pressure and Time of Peak*

Case		Peak Differential Pressure, psi	Time of Peak Differential Pressure, sec
6 in.	RCIC Line Break In Upper Head Region	11.46	0.75
24 in.	Recirculation Line In Lower Region	11.17	1.10

* Original rated power.

Table 6.2-28

Analytical Sequence of Events in Secondary Containment

Post-LOCA Time		Events in Secondary Containment
0	-	Reactor building differential pressure is 0.0-in. w.g. between inside and outside of building
	-	Loss of offsite power
	-	All normal operating equipment ceases to function
0.1 sec[a]	-	Emergency building lighting on (automatic)
15 sec	-	Emergency power on (automatic)
120 sec	-	Standby gas treatment system on (automatic)
300 sec	-	Full service water flow to ECCS pump room coolers
20 min	-	Building pressure reduced to -0.25-in. w.g.
1 hr[b]	-	Normal lighting off (manual)
12 hr	-	One fuel pool cooling loop on (manual)

[a] Analysis conservatively assumes emergency lighting is on after 0.1 sec even though diesels take 15 sec to restore power.

[b] Normal lighting terminates on FAZ. Analysis conservatively assumes failure to terminate for 1 hr.

Table 6.2-30

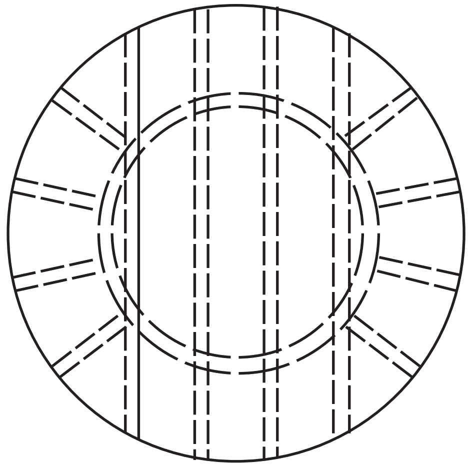
Post-LOCA Transient Heat Input Rates
to Secondary Containment

Heat Source	Heat Input, Btu/hr	Remarks
Primary containment walls (PCW)	$q_1 = 33,161\ (t_{pcw}-t_{air})$, for $t_{air} < t_{pcw}$ $q_1 = 0$, for $t_{air} > t_{pcw}$	$t_{pcw} = 105°F$ constant $t_{air,\ r} =$ reactor building air temperature
Normal equipment decay heat	Electrical equipment (combined)	Max. eq. surface
	$q_2 = 1475\ (150e^{-T}-t_{air})$, for $t_{air} < 150e^{-T}$	Temperature $= 150°F$ for $T \leq 0$
	$q_2 = 0$, for $t_{air} \geq 150e^{-T}$	
	Piping (combined)	Max. eq. surface Surface temp $= 182°F$
	$q_3 = 664\ (182e^{-T} - t_{air})$, for $t_{air} < 182\ e^{-T}$	for $t \leq 0$
	$q_3 = 0$, for $t_{air} \geq 182e^{-T}$	
Emergency equipment	Emergency lighting ($t \geq 0$ sec)	
	$q_4 = 203,700$	
	Standby gas treatment system ($T \geq 34$ sec) $q_5 = 8800$	
	Emergency core cooling system ($T \geq 30$ sec) $q_6 = 4476\ (t_{cw} - t_{air})$, for $t_{air} < t_{cw}$ $q_6 = 0$, for $t_{air} \geq t_{cw}$	T,hr / tcw,* °F 0 / 95 2 / 180 50 / 143 100 / 132 *cw = cooling water

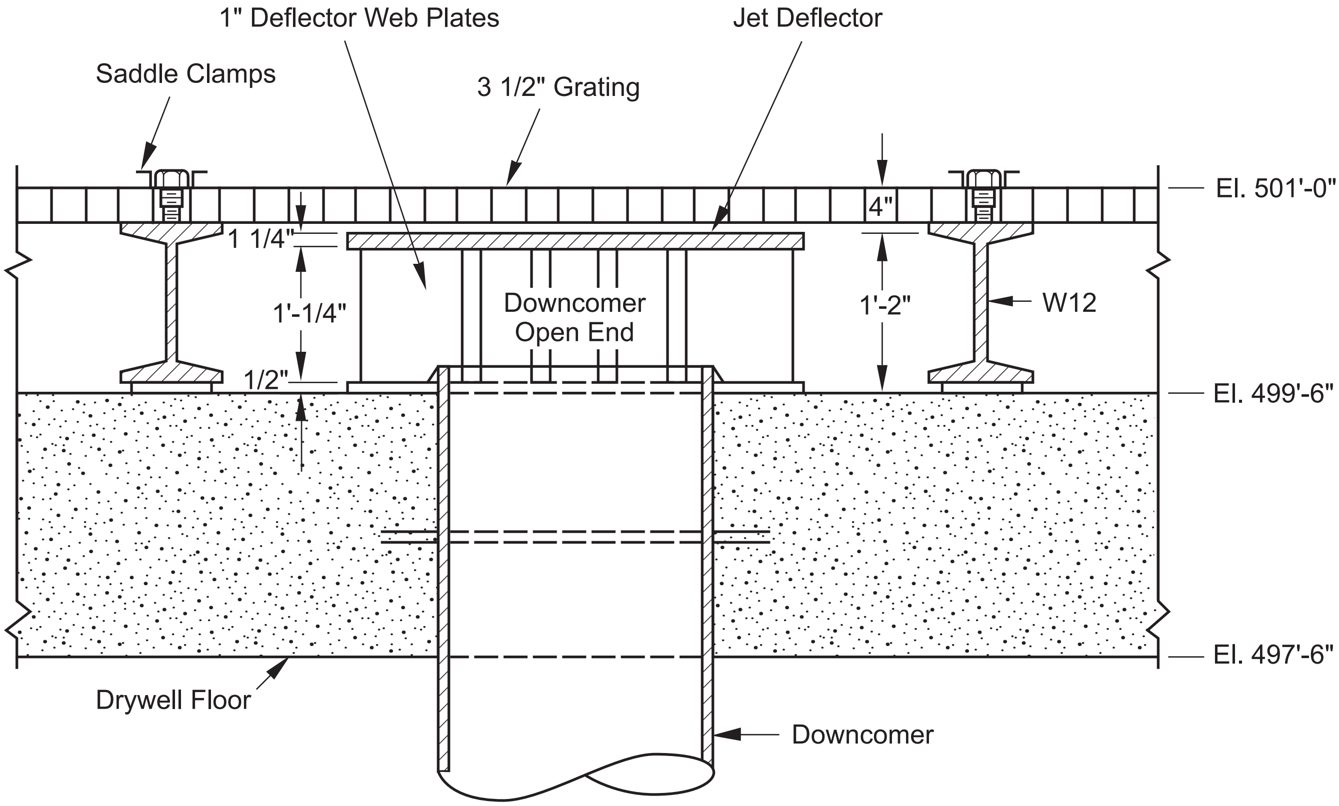
Table 6.2-30

Post-LOCA Transient Heat Input Rates
to Secondary Containment (Continued)

Heat Source	Heat Input, Btu/hr	Remarks
Fuel pool sensible heat	$q_7 = 299.2\ (t_{pw}\text{-}t_{air})^{4/3}$	t_{pw} = pool water temp. °F
Pool evaporation heat	$q_8 = 1385.19\ (t_{pw} - t_{air})^{1/3}\ (W_{ps} - W_{air})\lambda p$	t_{pw} = pool water temp. °F W_{ps} = humidity ratio ° Saturated moist air Evaluated at t_{pw} of wet surface (1bw/1ba) W_{ps} = humidity ratio of moisture air (1bw/1ba) λp = heat of vaporization (1bw/1ba)
Infiltration air heat-up	$q_9 = -0.24945\ (t_{air} - 100) >$	
Structural steel heat-up	$q_{10} = -\ 11400\ (t_{air} - t_{steel})^{4/3}$	t_{steel} = steel temp (°F)
Total	$Q = q_1 + q_2 + q_3 + q_4 + q_5 + q_6 + q_7 + q_8 + q_9 + q_{10}$	$Q = \sum_{1=10}^{10} q_1$



Top View Of Jet Deflector



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Typical 24 in. Downcomer Vent with Jet Deflector

Draw. No. 900547.40	Rev.	Figure 6.2-1

Point Of Critical Flow

A. Recirculation Line
B. Cleanup Line
C. Combined Area of All Jet Pump Nozzles Associated with the Broken Loop

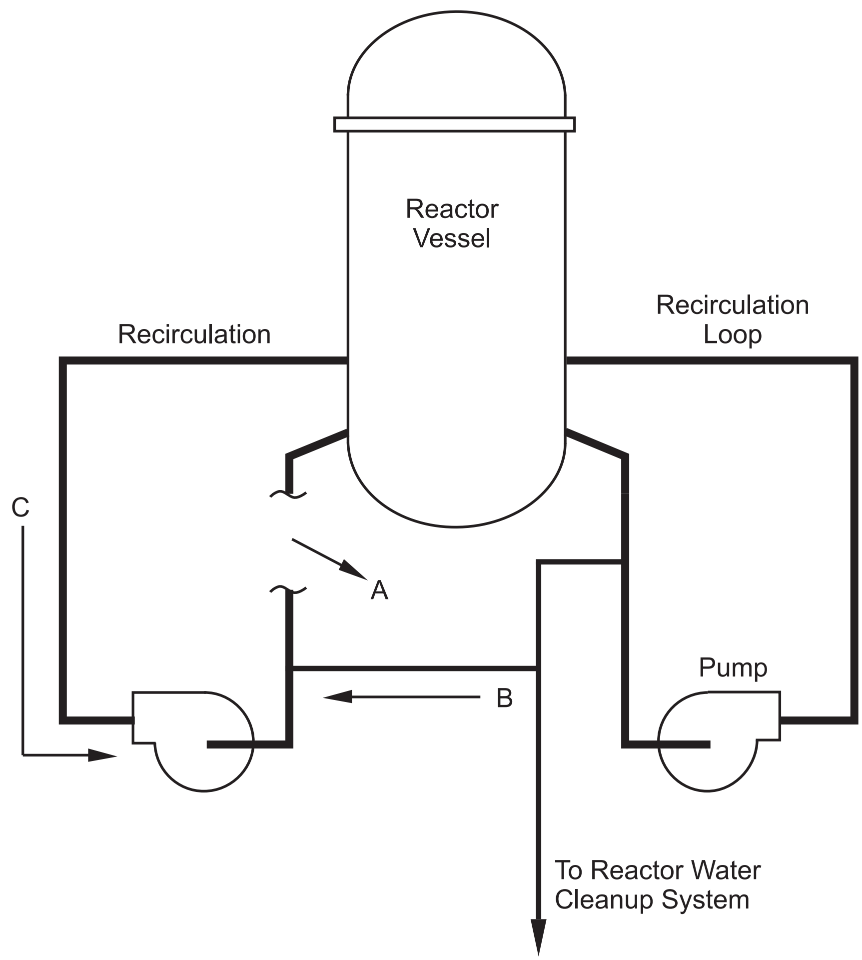
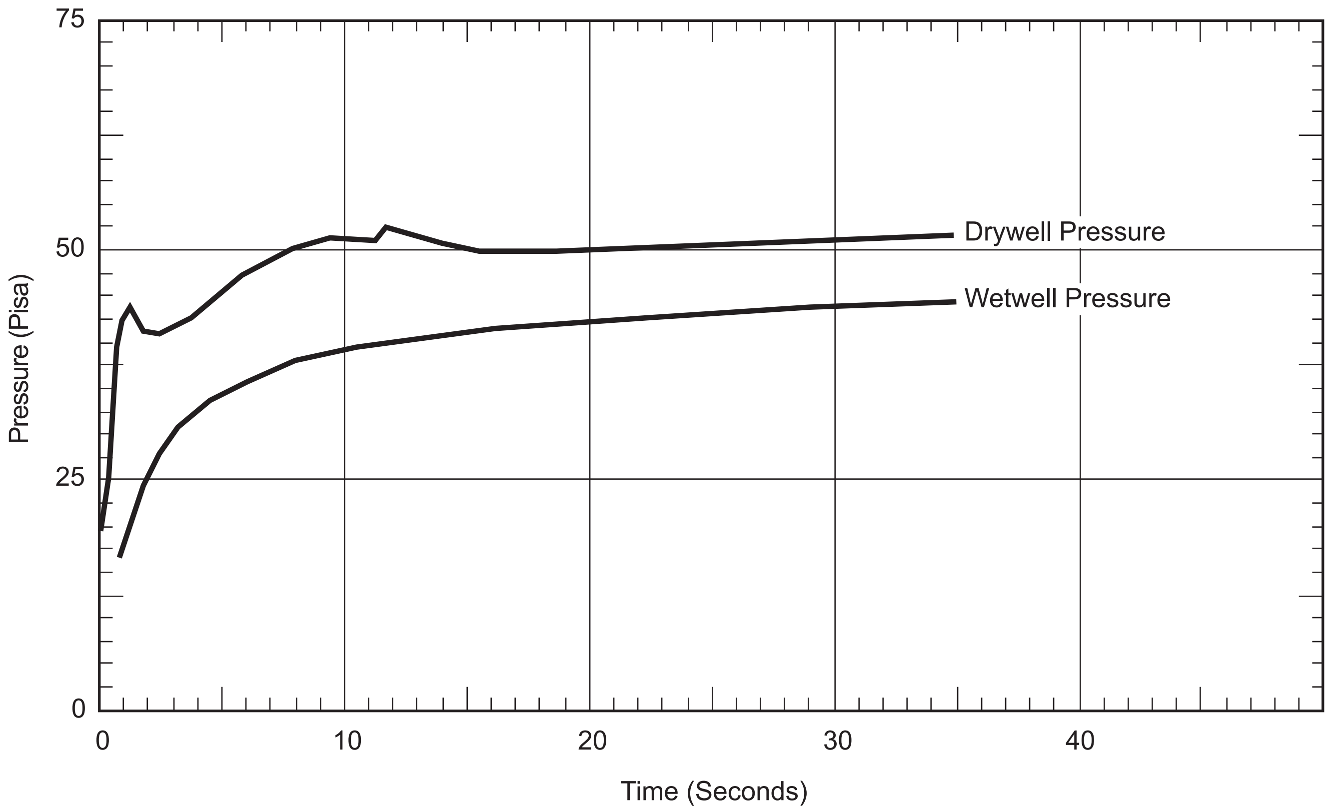
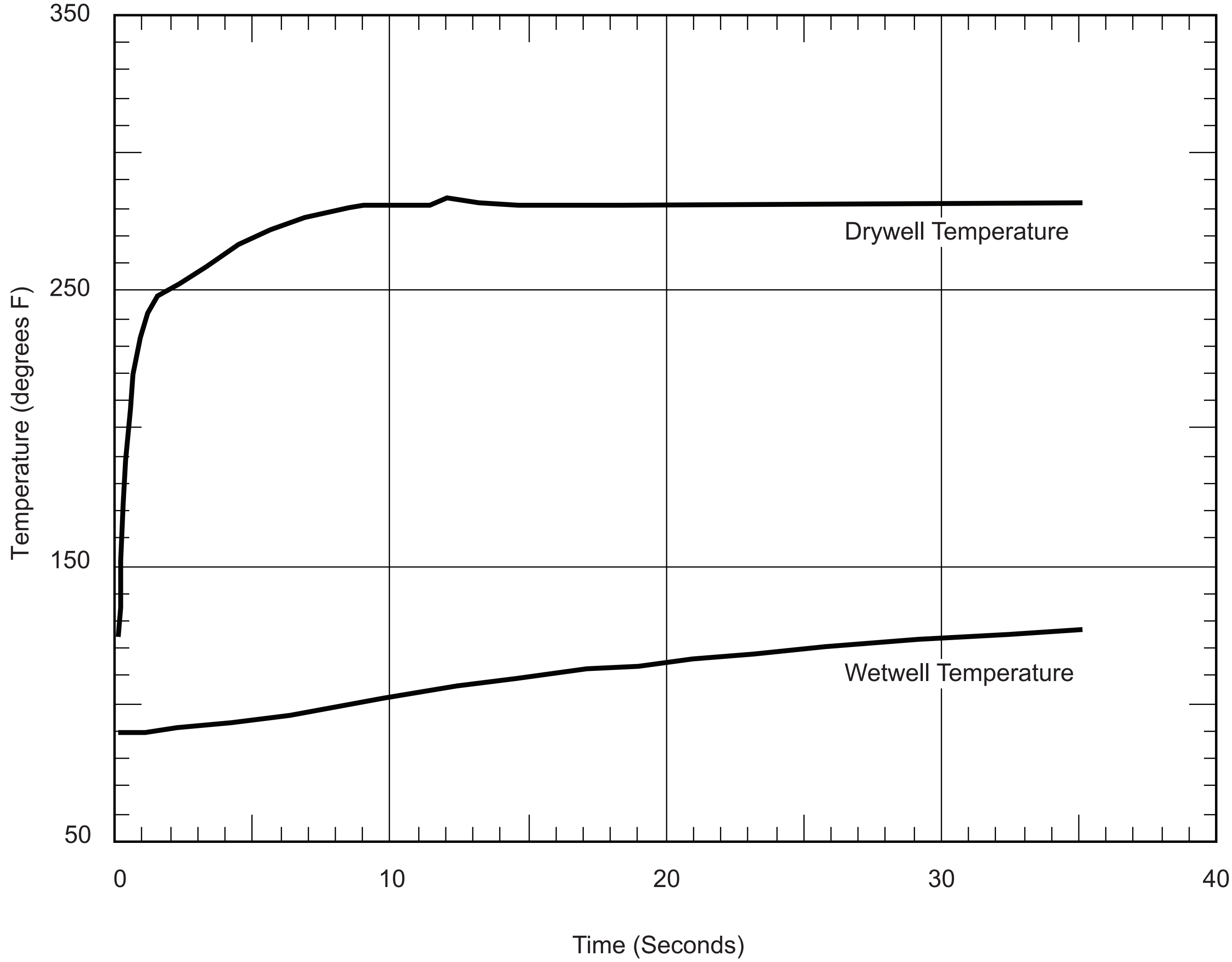


Diagram of the Recirculation Line Break Location

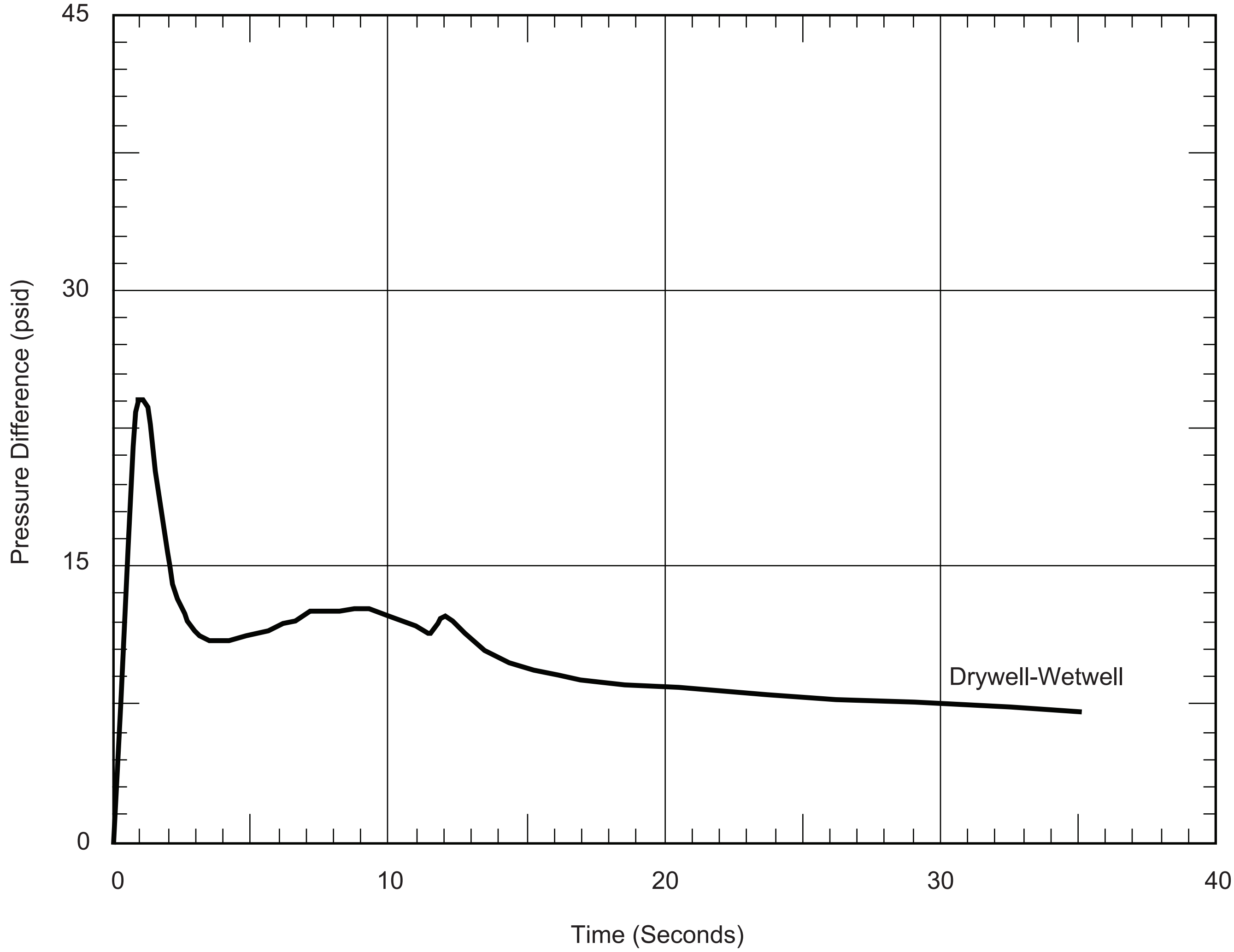


Columbia Generating Station Final Safety Analysis Report	Pressure Response for Recirculation Line Break (Initial Containment Pressure 2 psig)
	Draw. No. 900547.37 | Rev. | Figure 6.2-3



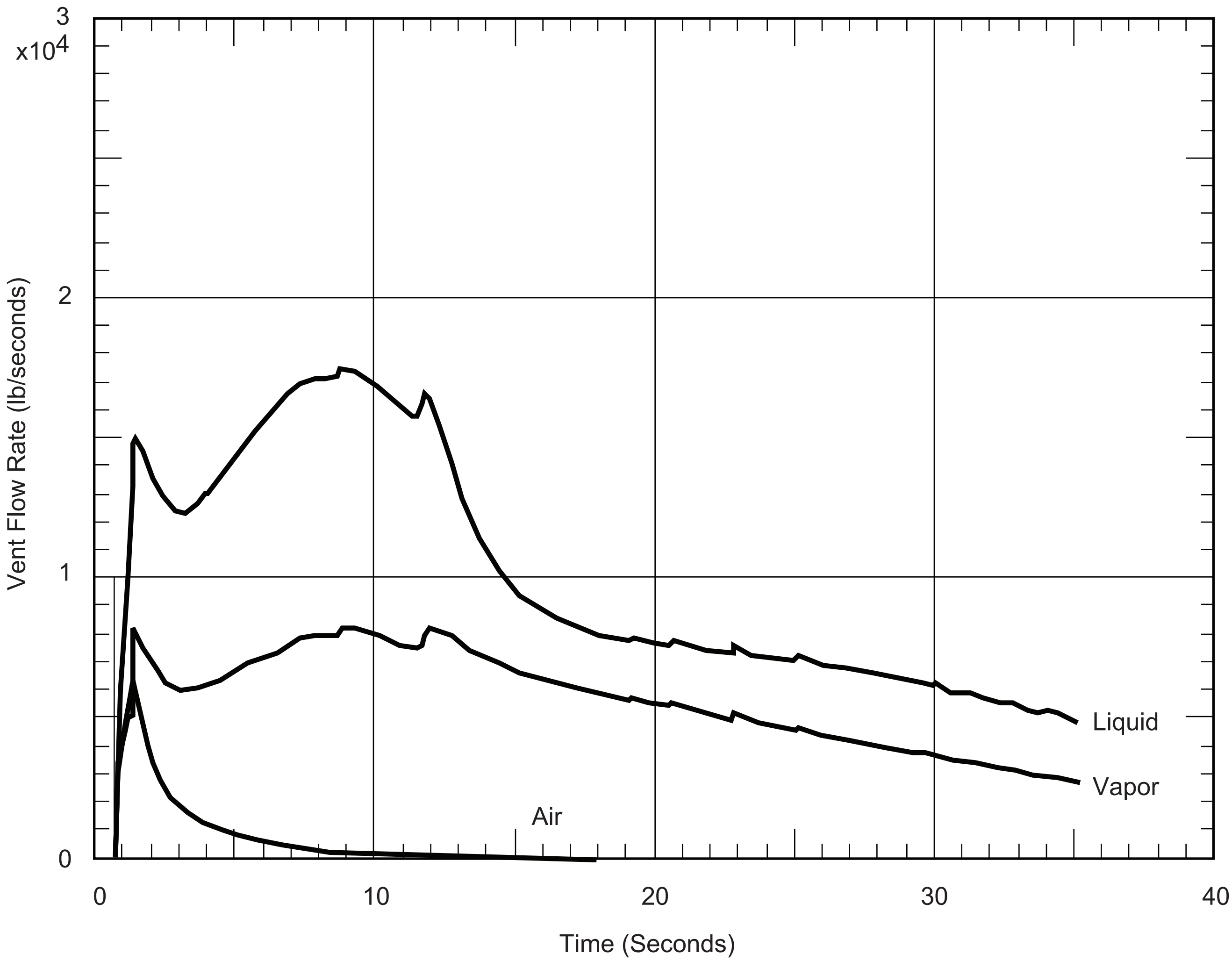
Temperature Response for Recirculation Line Break (Initial Containment Pressure 2 psig)

Draw. No. 960222.02 | Rev. | Figure 6.2-4



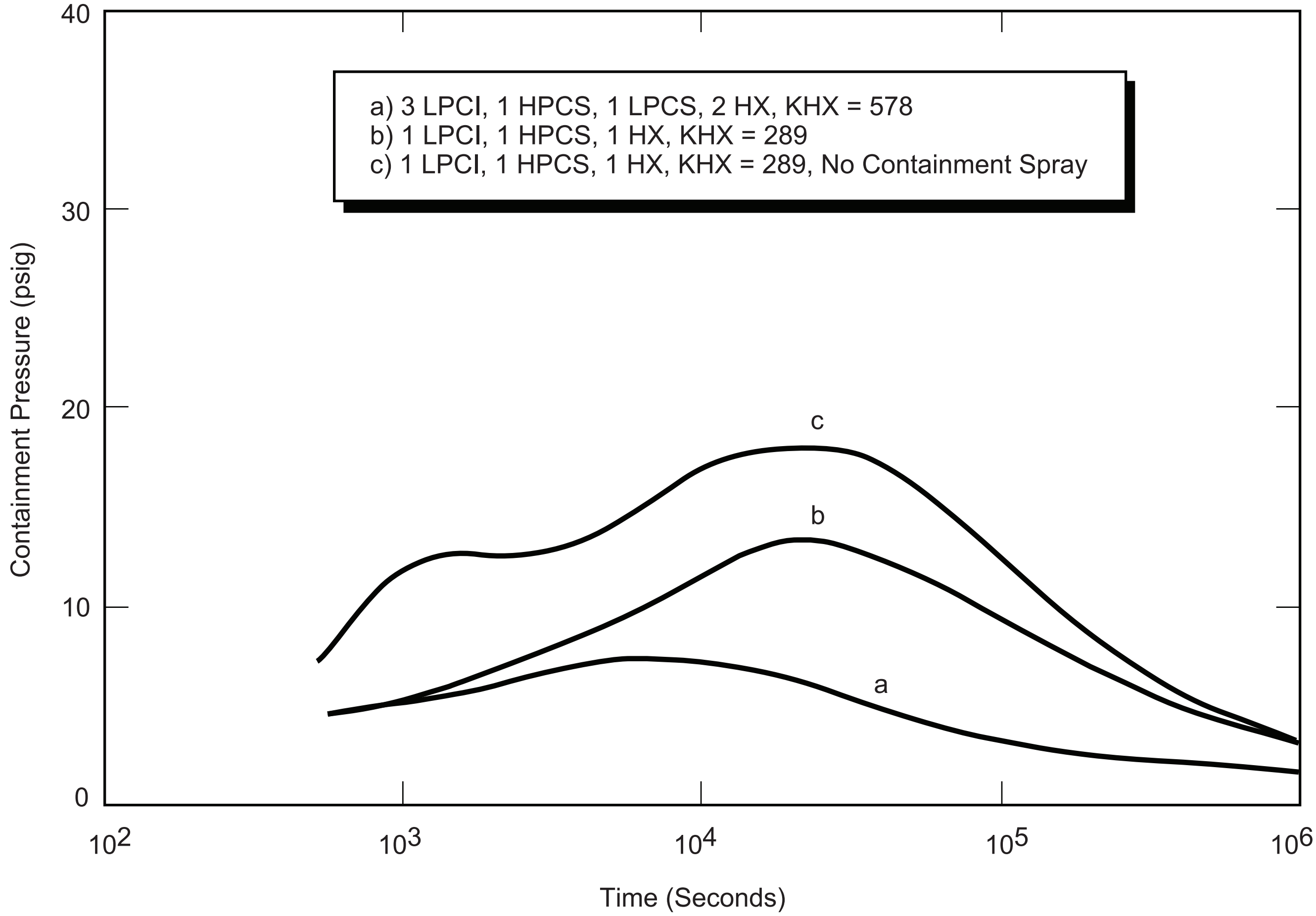
Drywell Floor ΔP Response for Recirculation Line Break (Initial Containment Pressure 2 psig)

Draw. No. 960222.03 | Rev. | Figure 6.2-5



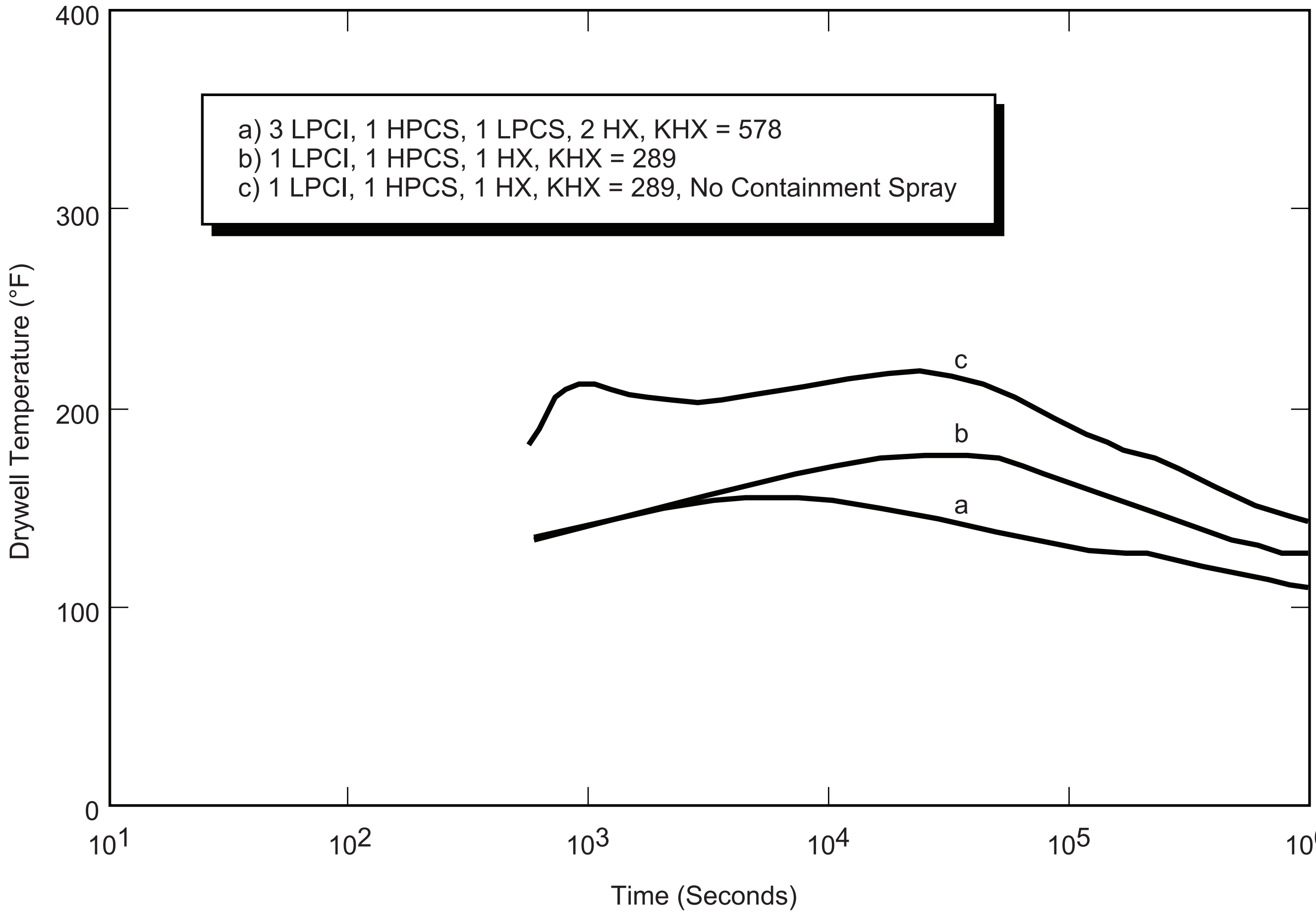
Containment Vent System Flow Rate for Recirculation (Initial Containment Pressure 2 psig)

Draw. No. 960222.04 | Rev. | Figure 6.2-6

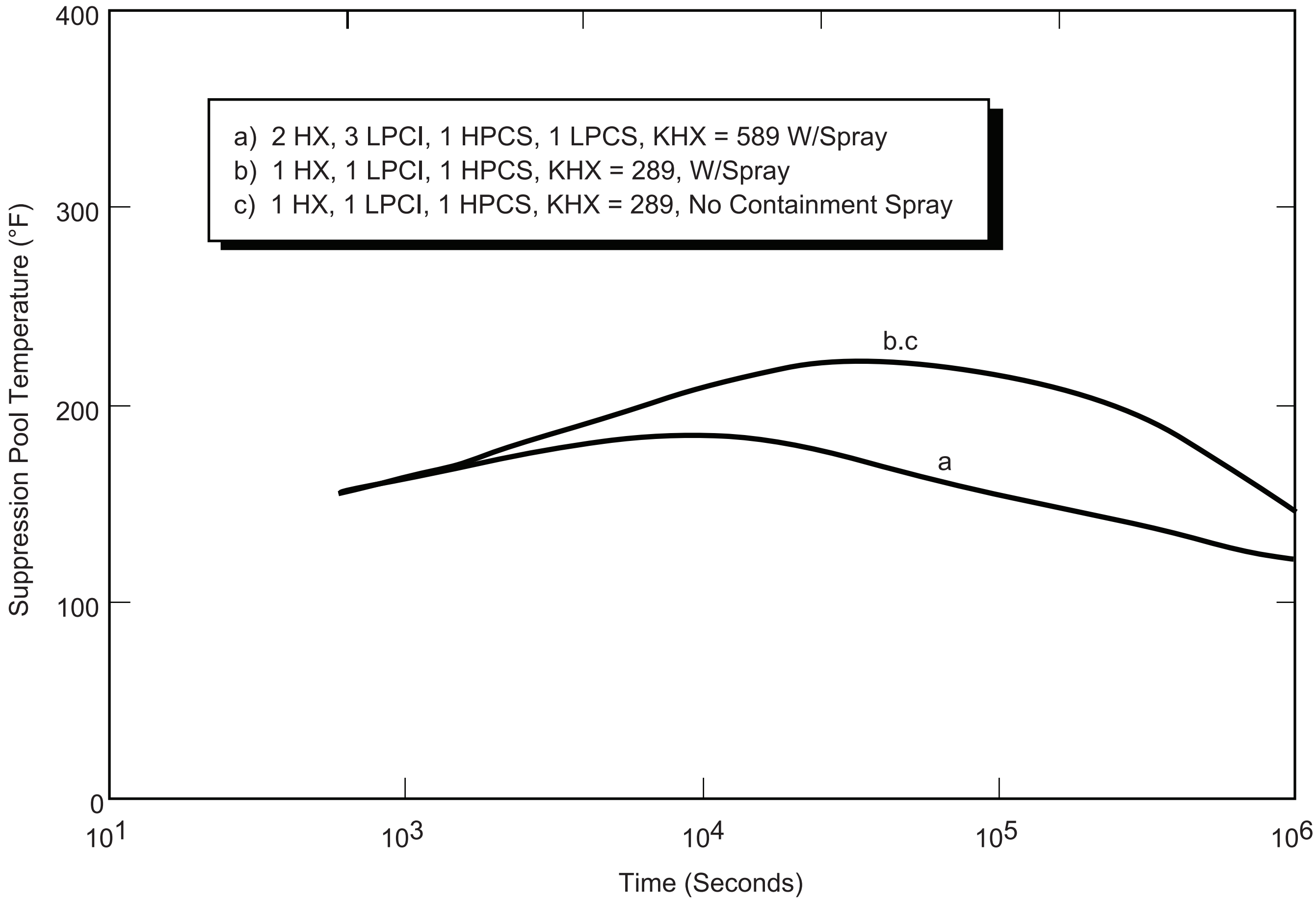


Containment Pressure Response Cases A, B, and C - Original Rated Power

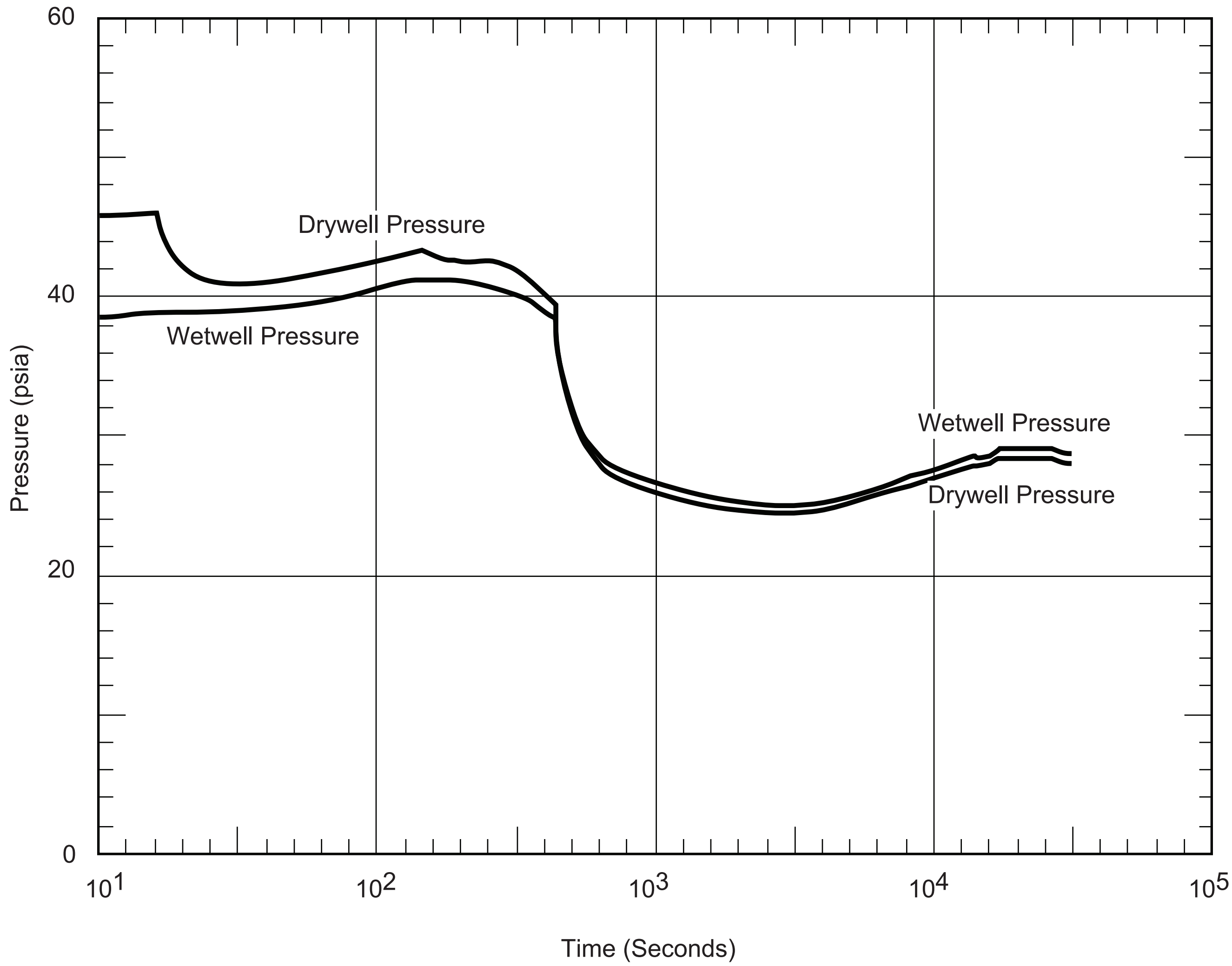
Draw. No. 960222.67 | Rev. | Figure 6.2-7



Drywell Temperature Response Cases A, B, and C - Original Rated Power

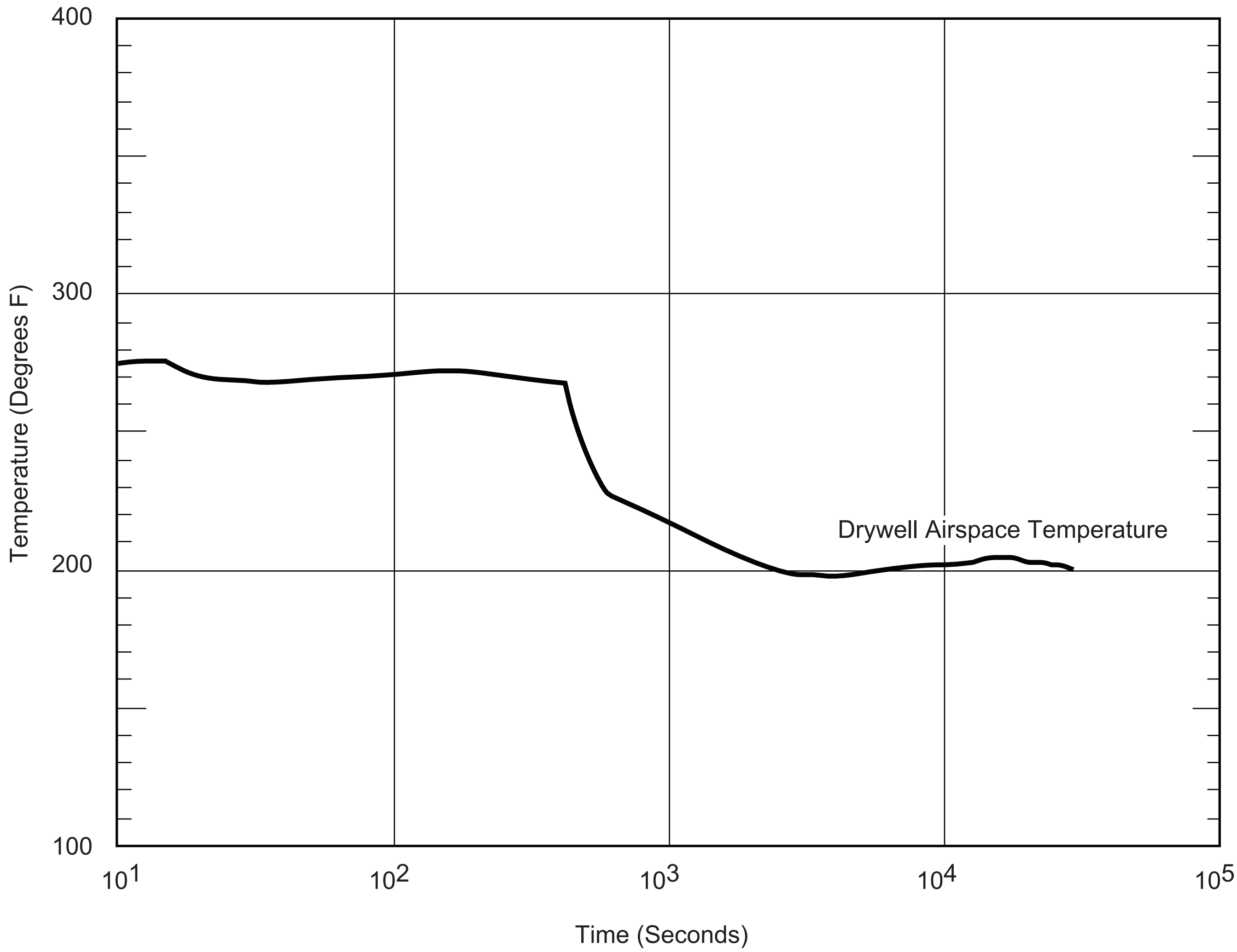


Suppression Pool Temperature Response, Long-Term Response - Original Rated Power



Containment Pressure Response - Case C
Uprated Power

Draw. No. 960222.05 | Rev. | Figure 6.2-10



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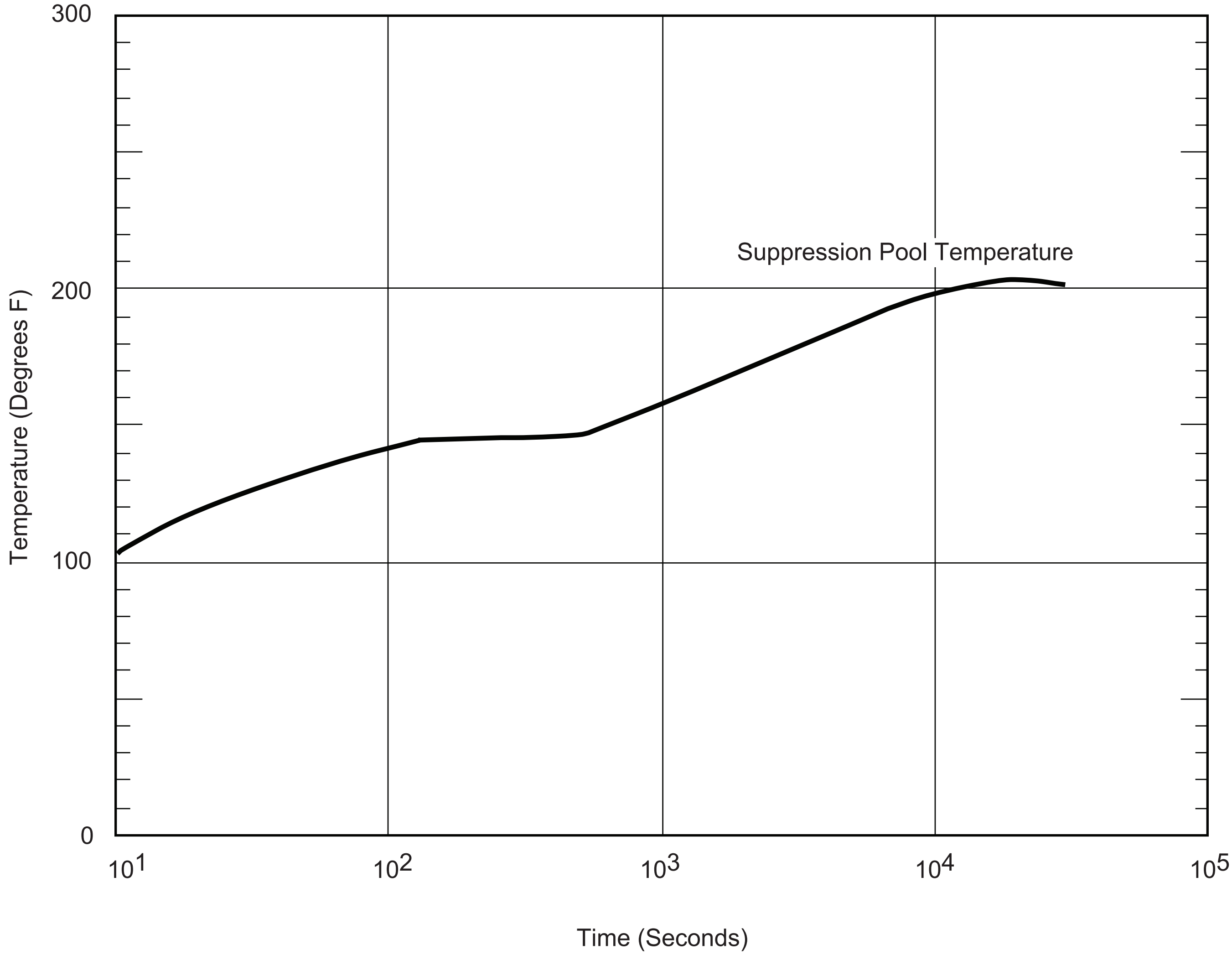
Drywell Temperature Response - Case C
Uprated Power

Draw. No. 960222.06	Rev.	Figure 6.2-11



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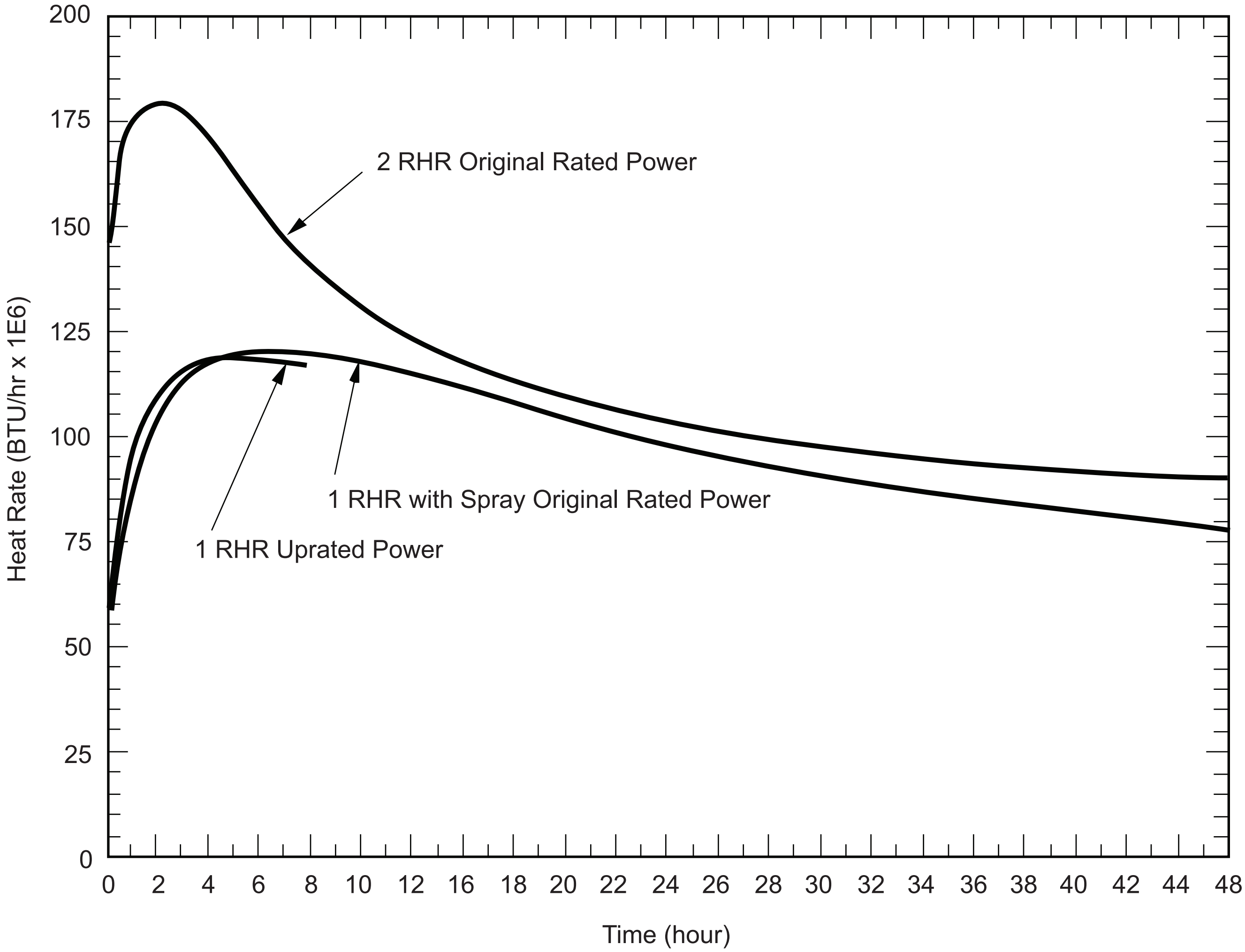
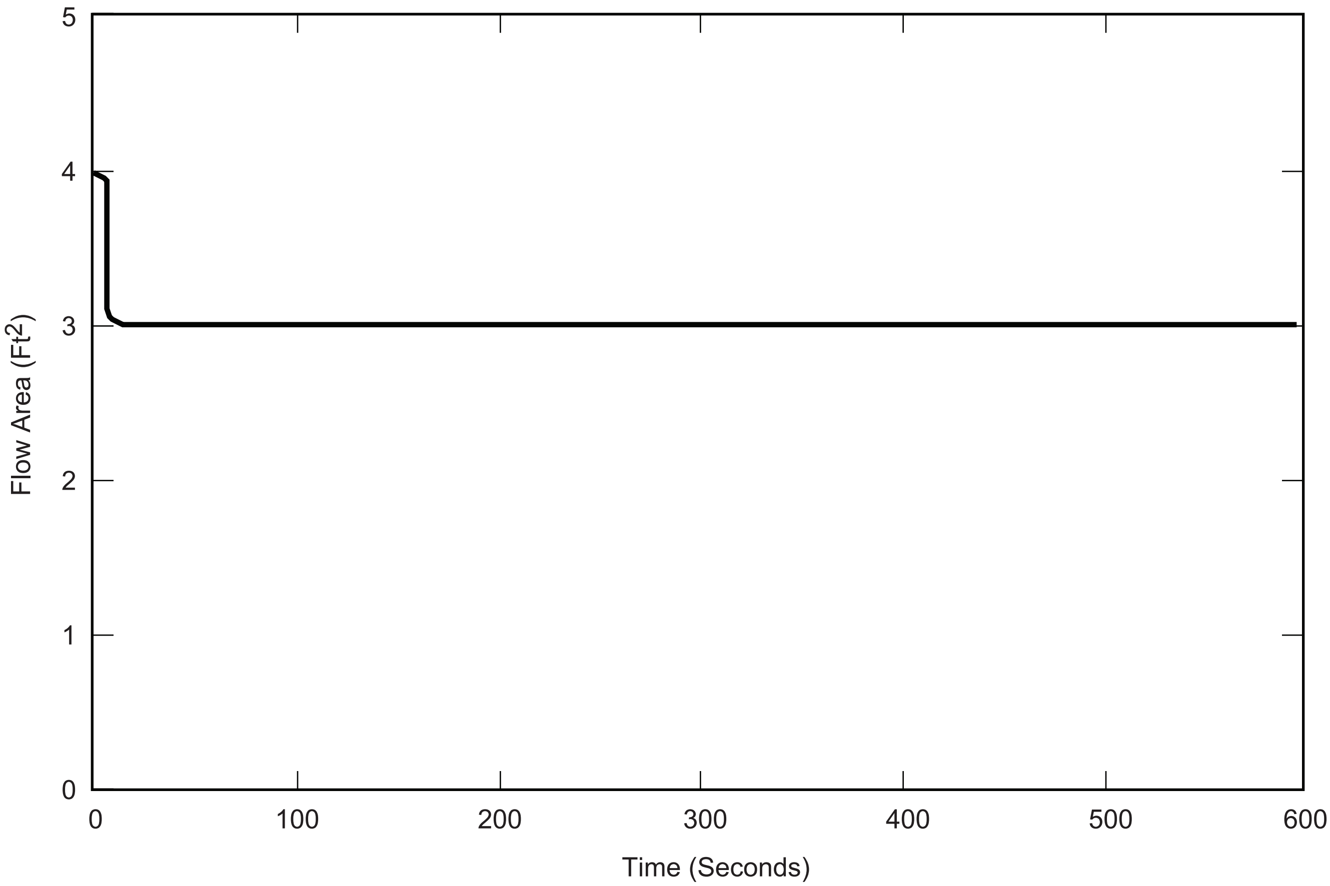
Suppression Pool Temperature Response - Case C
Uprated Power

Draw. No. 960222.07	Rev.	Figure 6.2-12

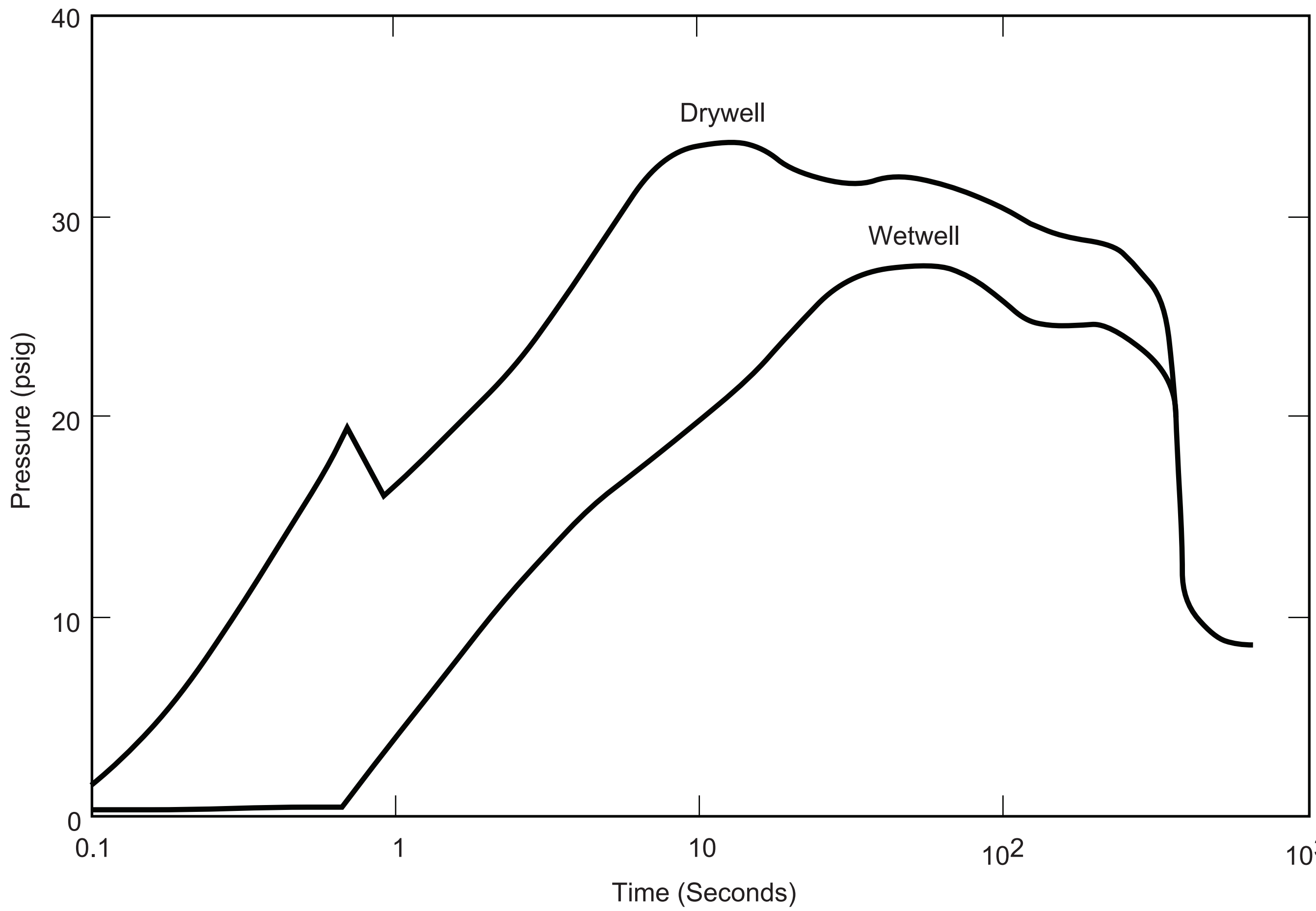


Columbia Generating Station Final Safety Analysis Report	Residual Heat Removal Rate		
	Draw. No. 960222.15	Rev.	Figure 6.2-13



Effective Blowdown Area Main Steam Line Break

Draw. No. 960222.28 | Rev. | Figure 6.2-14



Columbia Generating Station
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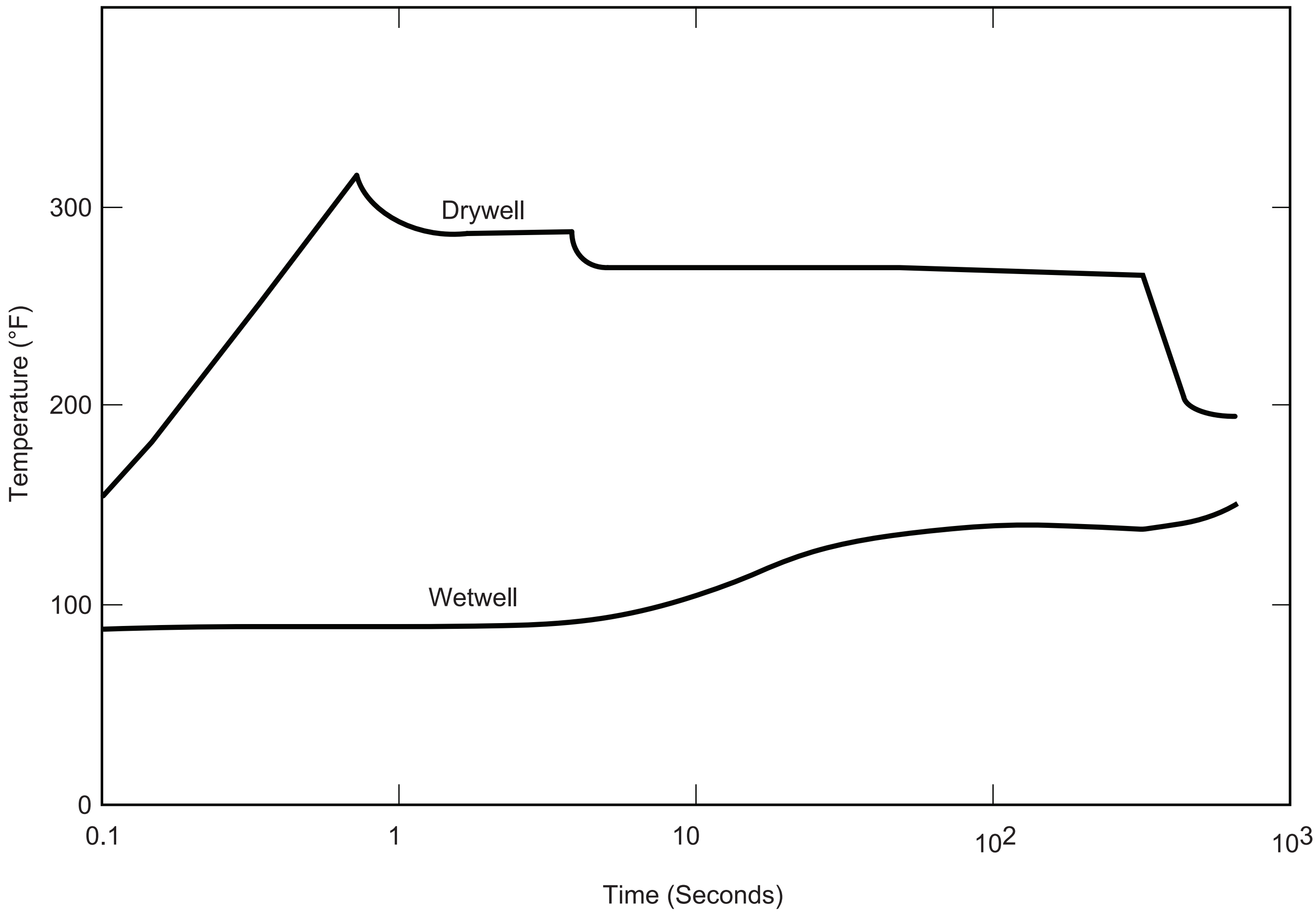
Bounding Pressure Response - Main Steam Line Break Original Rated Power

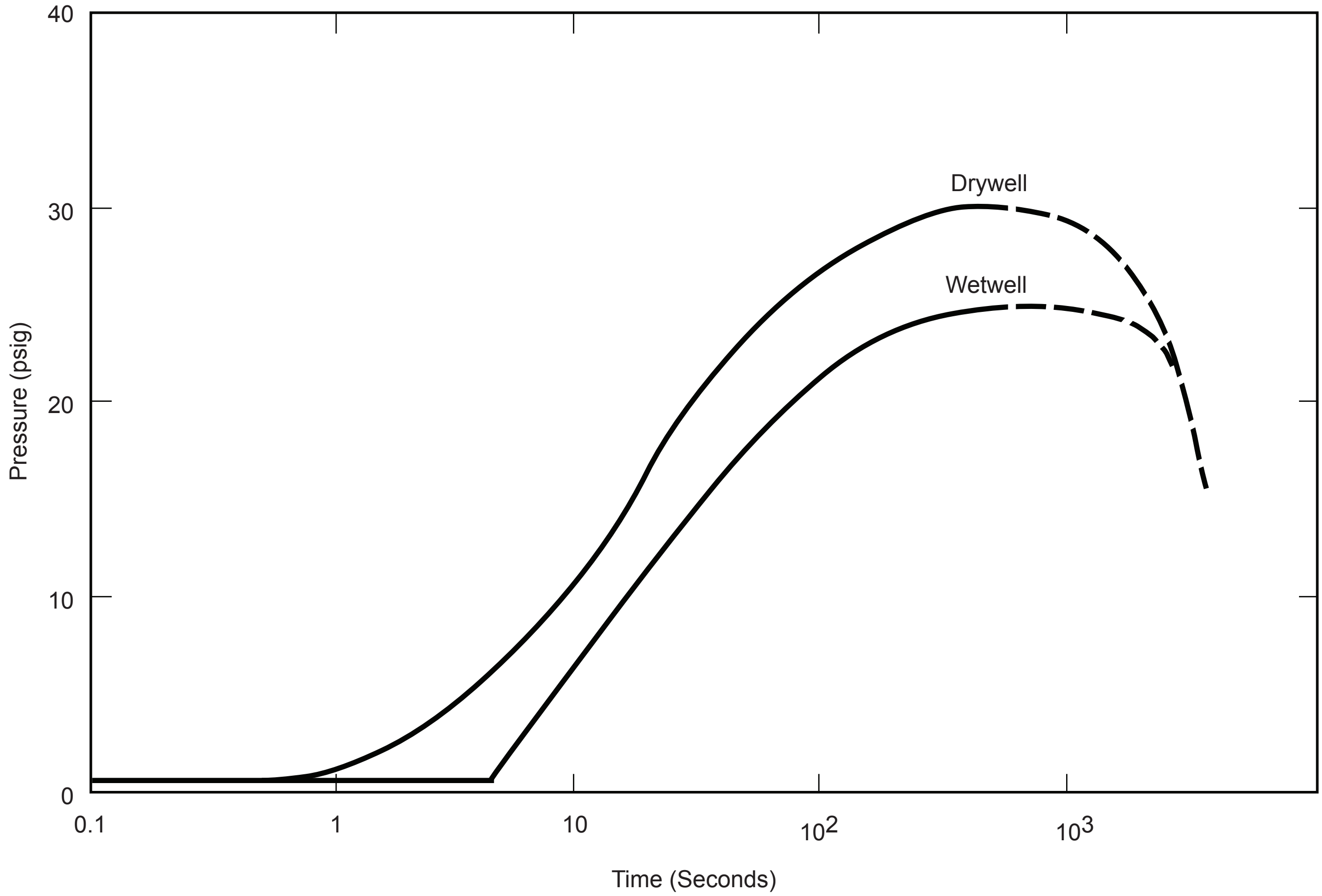
Draw. No. 960222.30 | Rev. | Figure 6.2-15



Bounding Temperature Response - Main Steam Line Break Original Rated Power

Draw. No. 960222.29 | Rev. | Figure 6.2-16

Amendment 53
November 1998



Columbia Generating Station
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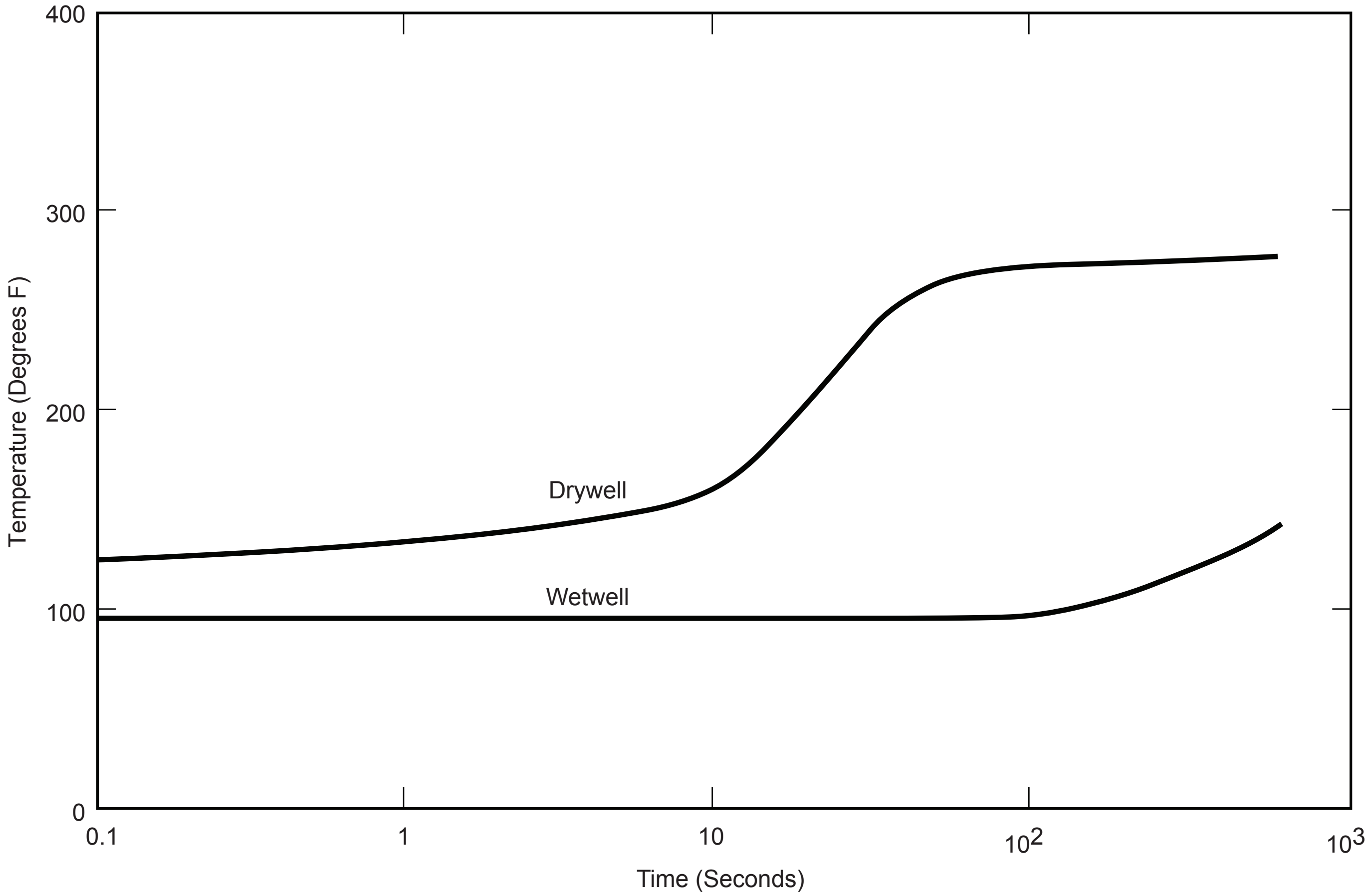
Pressure Response - Recirculation Line Break
($0.1\ ft^2$) Original Rated Power

Draw. No. 960222.31 | Rev. | Figure 6.2-17

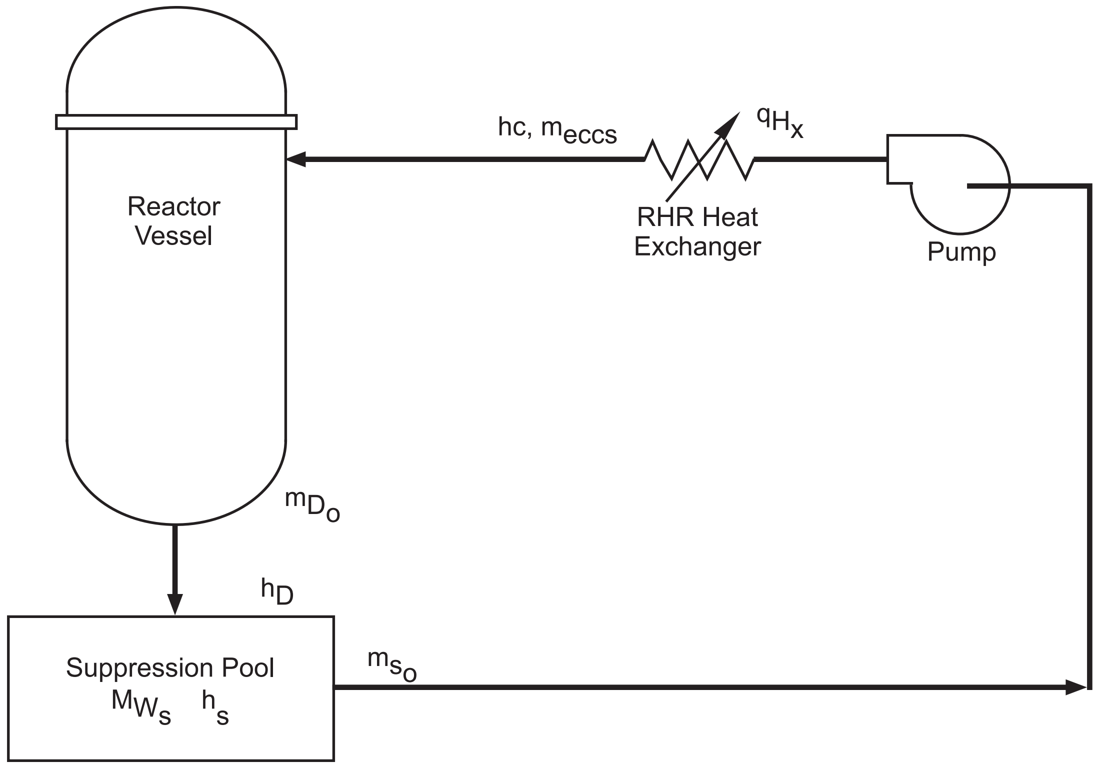
Form No. 960690



Columbia Generating Station
Final Safety Analysis Report

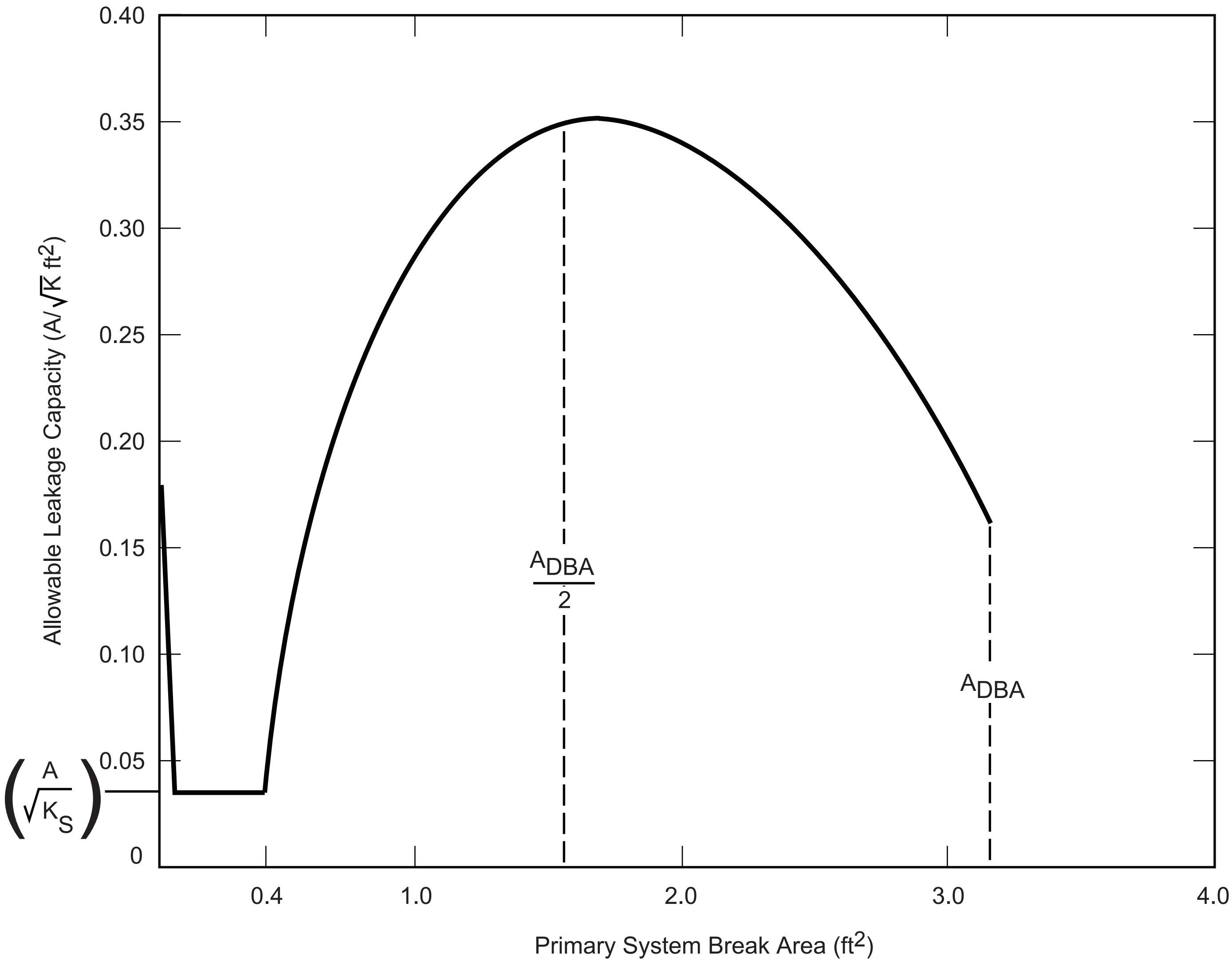
Temperature Response - Recirculation Line Break ($0.1\ ft^2$) Original Rated Power

Draw. No. 960222.32 | Rev. | Figure 6.2-18



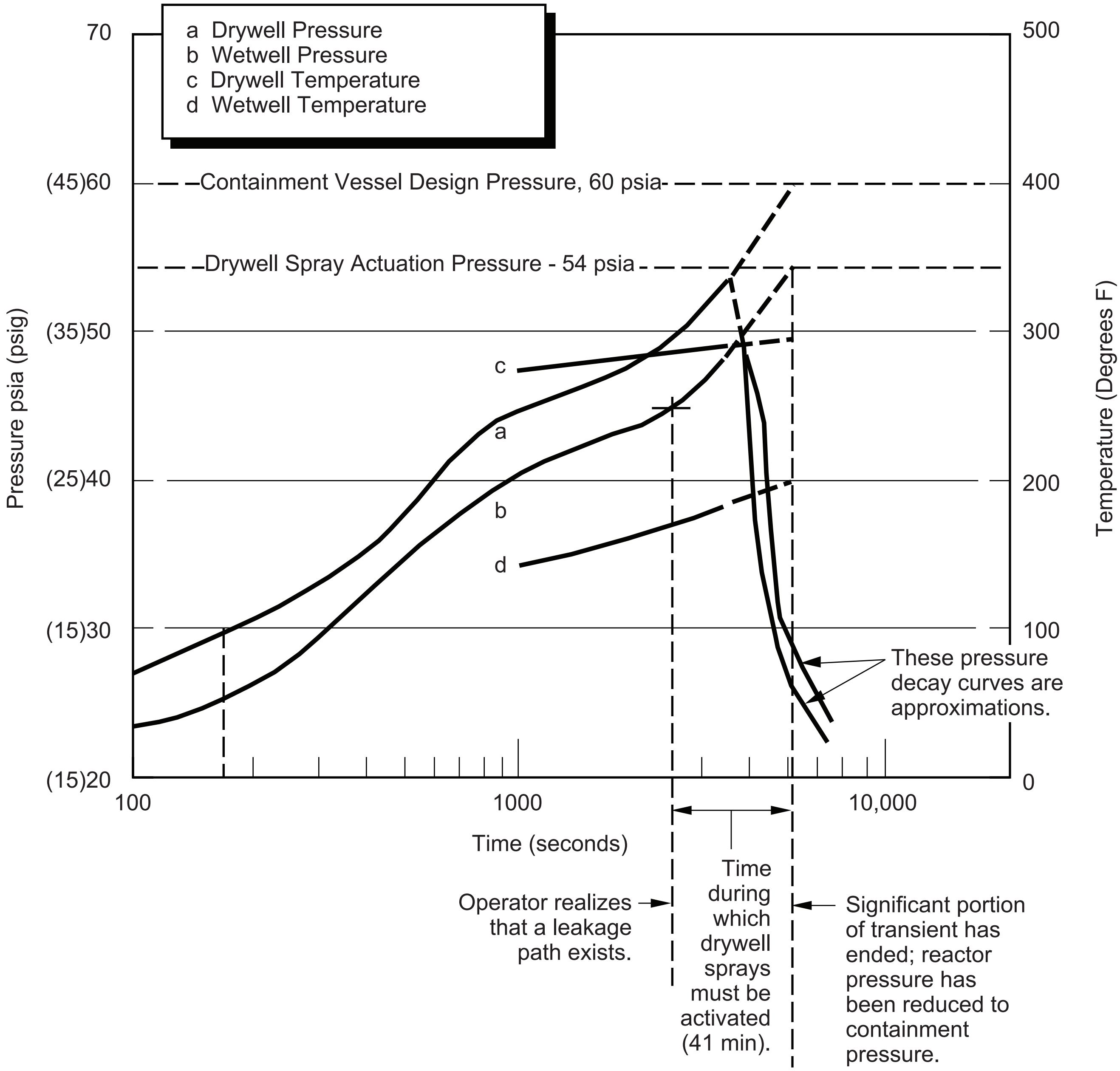
h_D	= Enthalpy Of Water Leaving Reactor, Btu/Lb
m_{D_o}	= Flow Rate Out Of Reactor, Lb/Sec
h_s	= Enthalpy Of Water In Suppresion Pool, Btu/Lb
m_{s_o}	= Flow Out Of Suppression Pool, Lb/Sec
q_{Hx}	= Heat Removal Rate Of Heat Exchanger, Btu/Sec
M_{W_s}	= Mass Of Water In Suppression Pool
q_D	= Core Decay Heat Rate, Btu/Sec
q_e	= Stored Energy Release Rate, Btu/Sec
h_c	= Enthalpy Of ECCS Flow To Reactor, Btu/Lb
m_{eccs}	= ECCS Flow Rate, Lb/Sec

Schematic of ECCS Loop



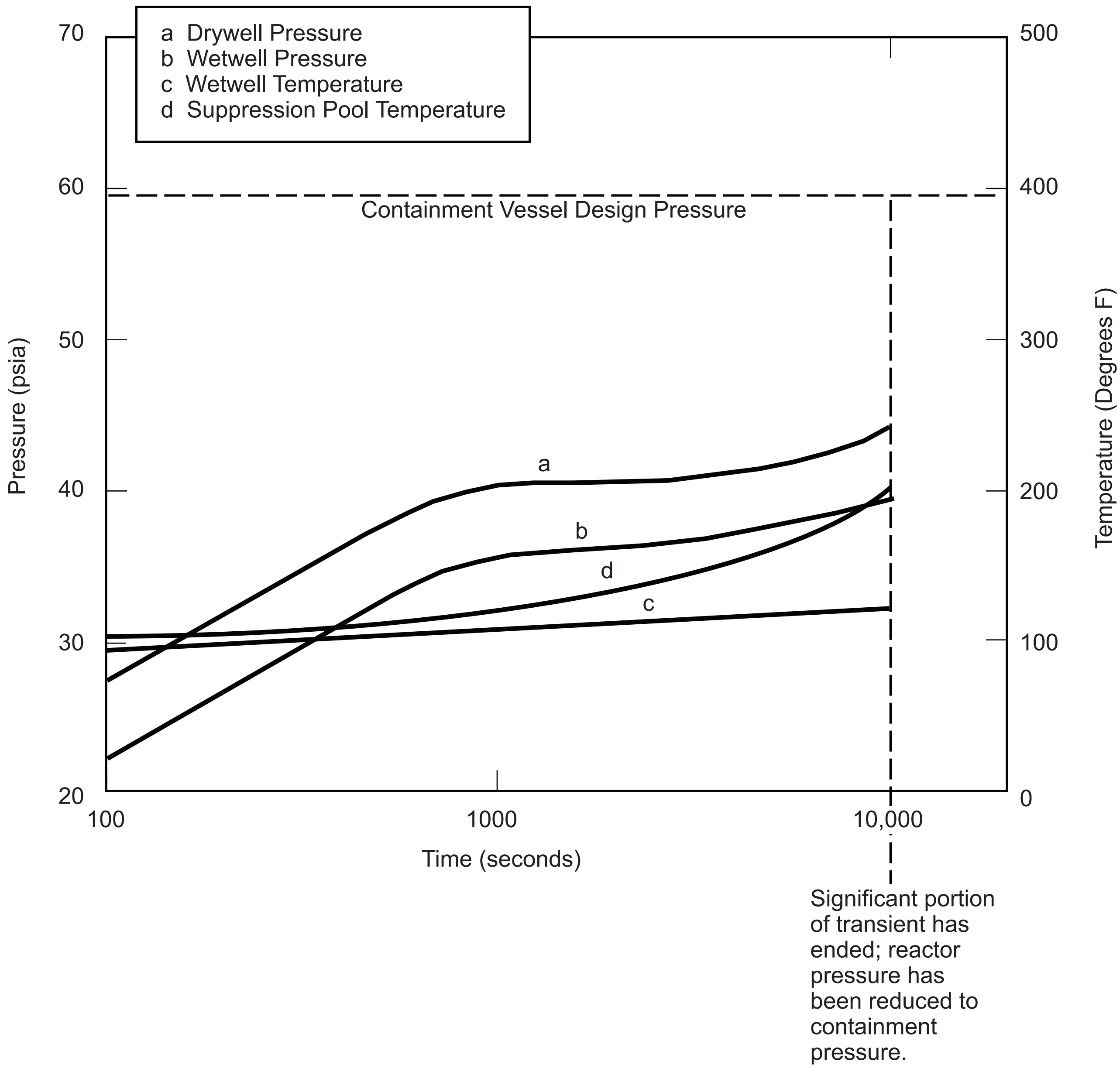
Allowable Leakage Capacity

Draw. No. 960222.39 | Rev. | Figure 6.2-20



Columbia Generating Station Final Safety Analysis Report	Containment Transient for Maximum Allowable Bypass Capacity $A\sqrt{x} = 0.050$		
	Draw. No. 960222.38	Rev.	Figure 6.2-21

Form No. 960690



Columbia Generating Station
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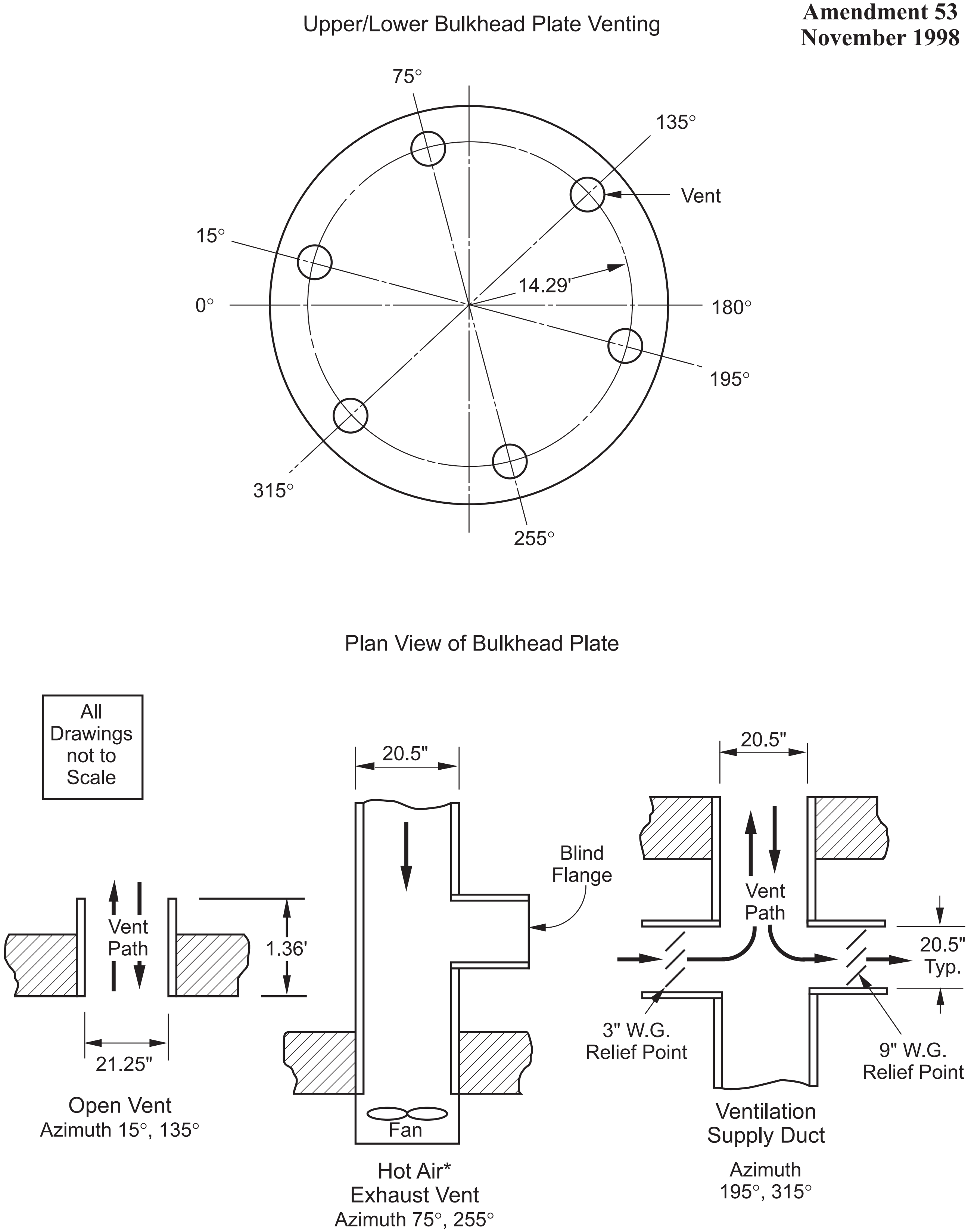
Containment Transient for $A/\sqrt{K} = 0.0045\ ft^2$

Draw. No. 960222.37 | Rev. | Figure 6.2-22



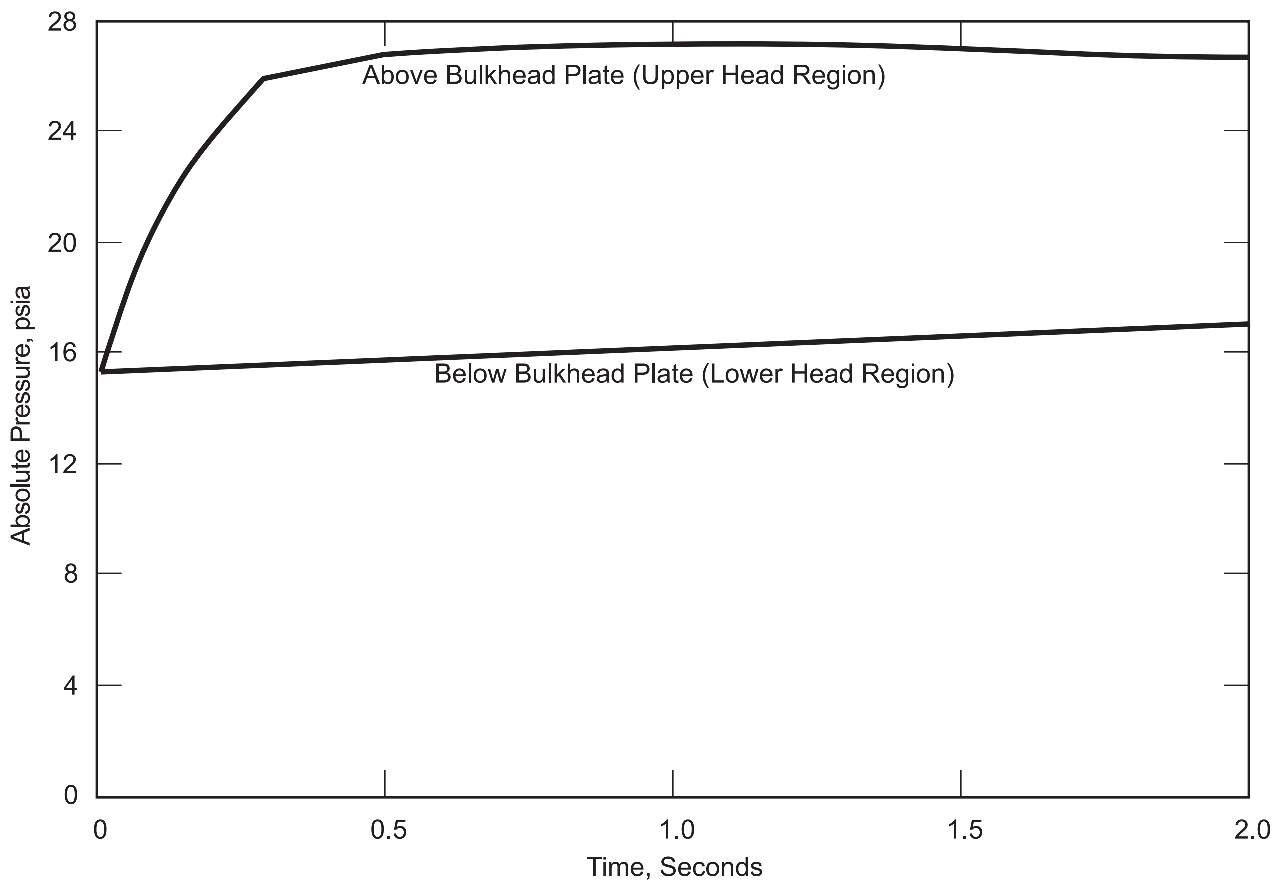
*Not Used in Compartment Pressure Analysis of Upper Head Region

Columbia Generating Station
Final Safety Analysis Report

Venting Through Bulkhead Plate

Draw. No. 920843.15	Rev.	Figure 6.2-24

Absolute Pressure in the Drywell Above and Below the Bulkhead Plate from a 6 Inch RCIC Line Break



Columbia Generating Station
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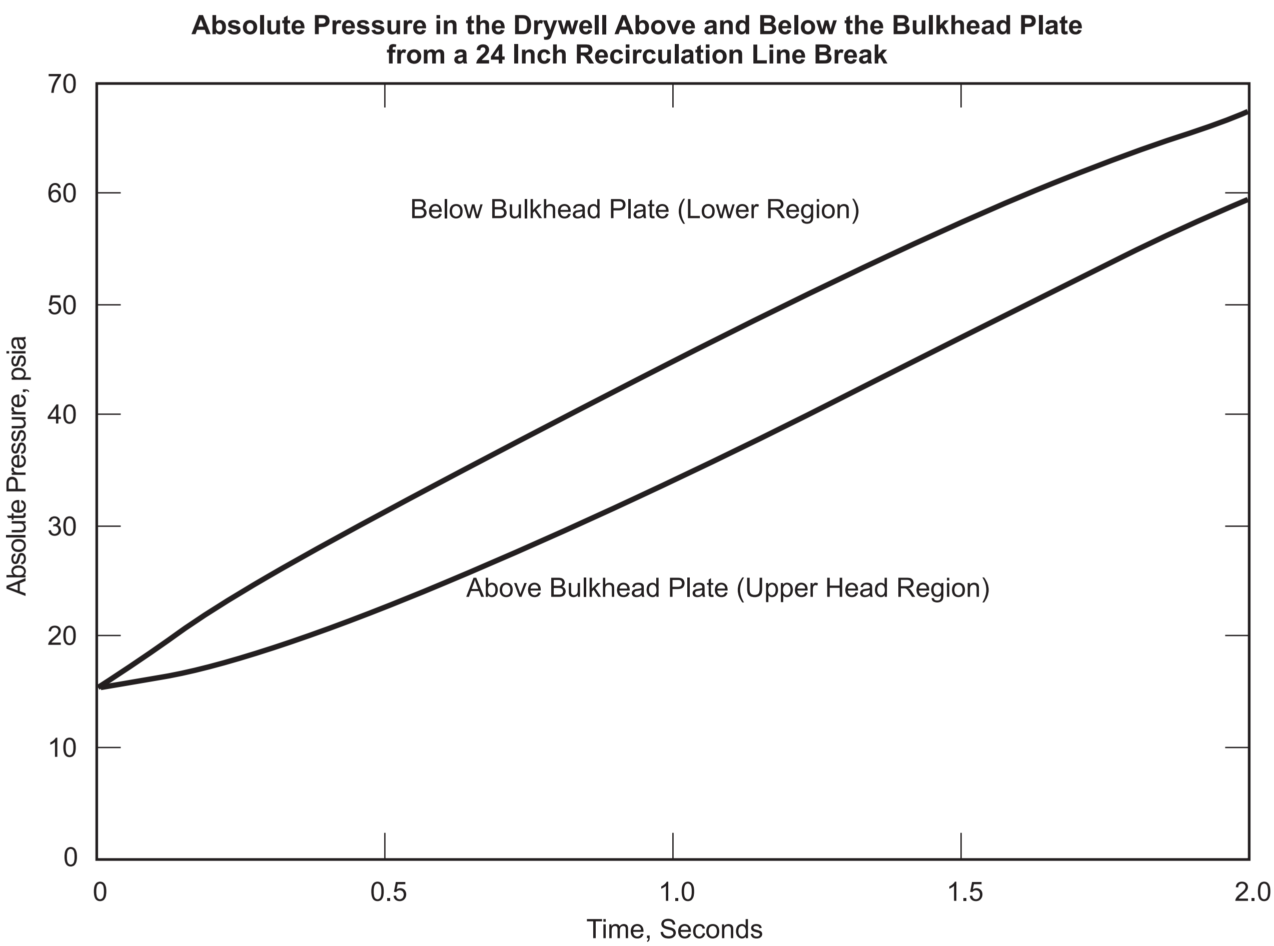
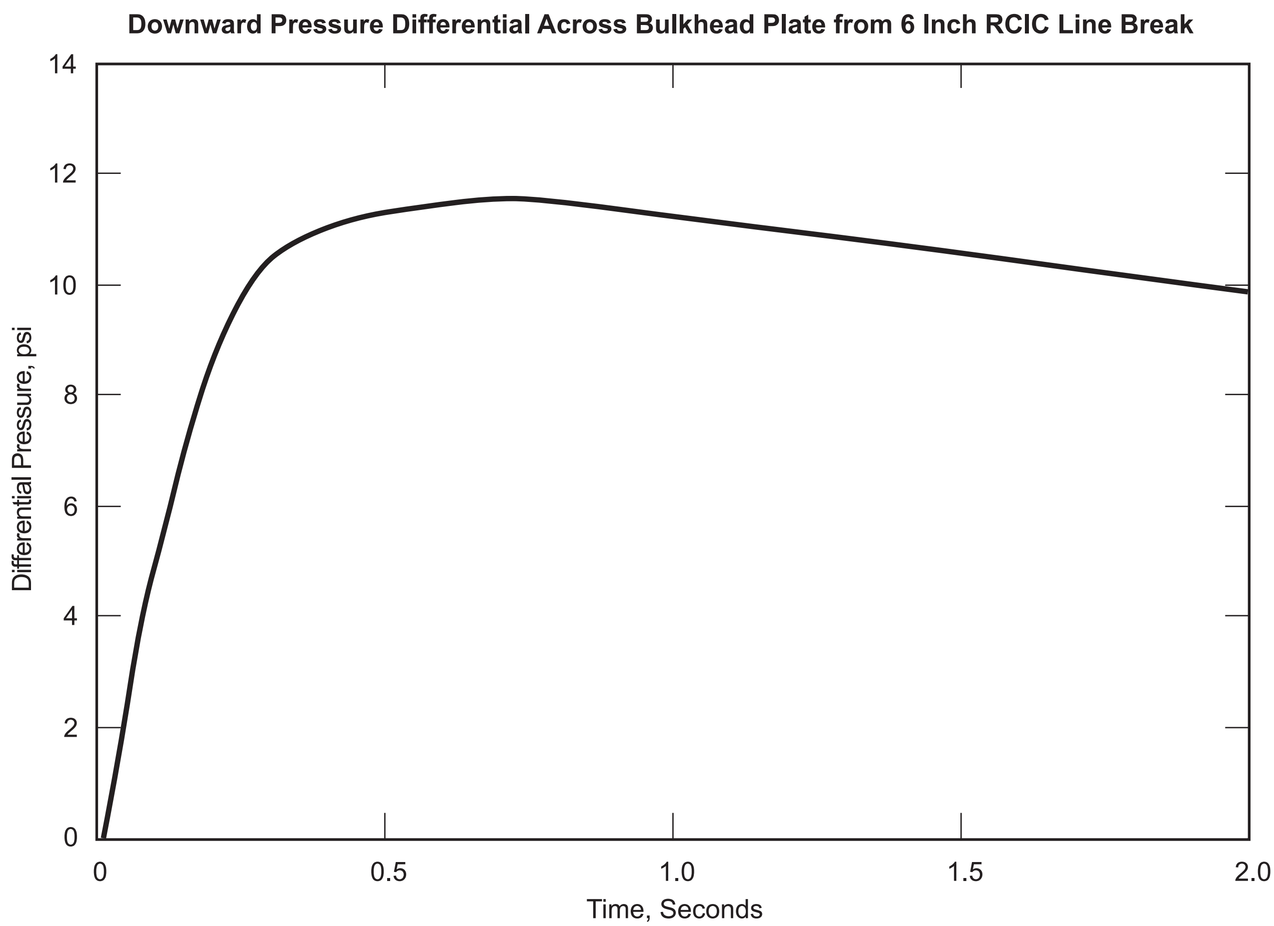
Absolute Pressure in Upper Head Region and Lower Region from 6 in. RCIC Line Break

Draw. No. 920843.11 | Rev. | Figure 6.2-25



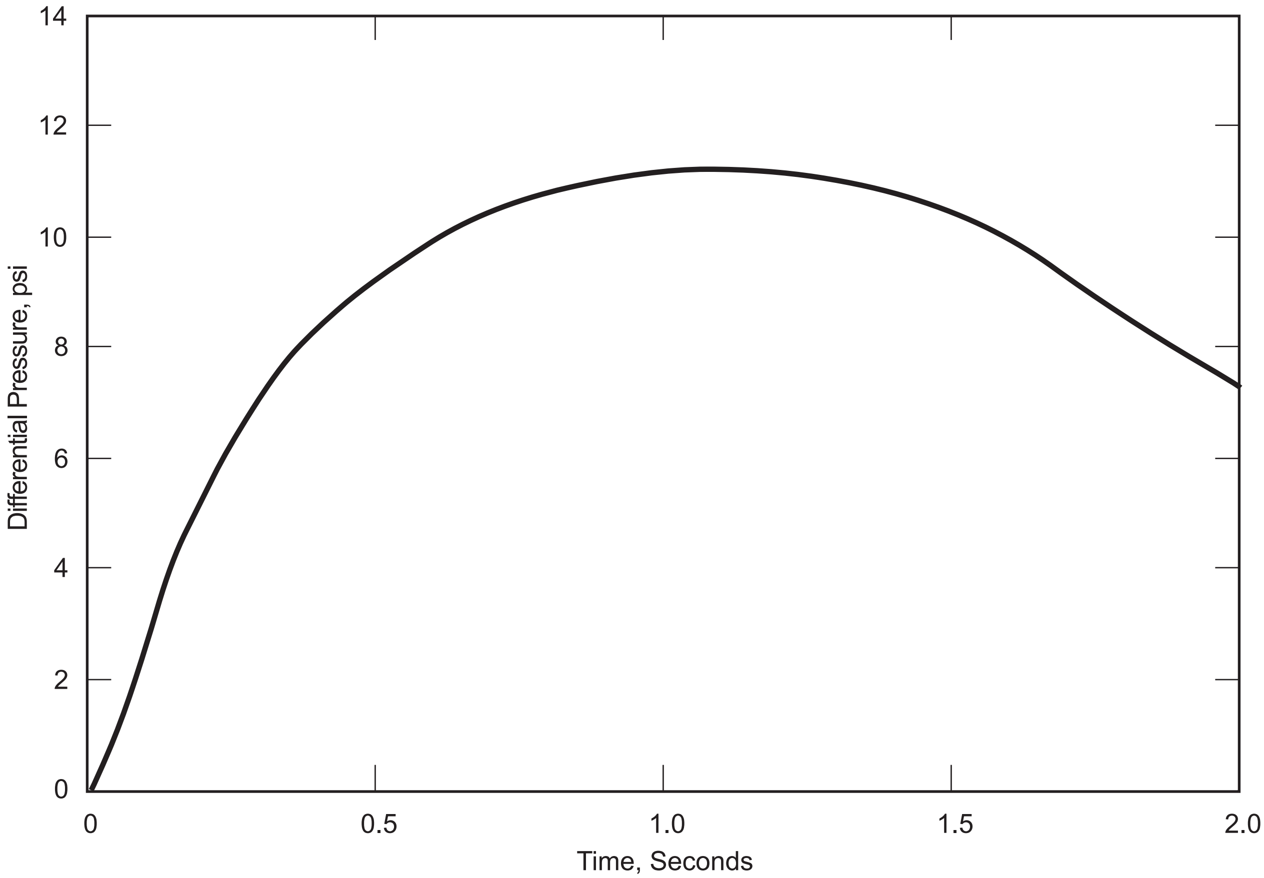
Absolute Pressure in Lower Region and Upper Head Region from 24 in. Recirculation Line Break



Downward Pressure Differential Across Bulkhead Plate from 6 In. Line Break

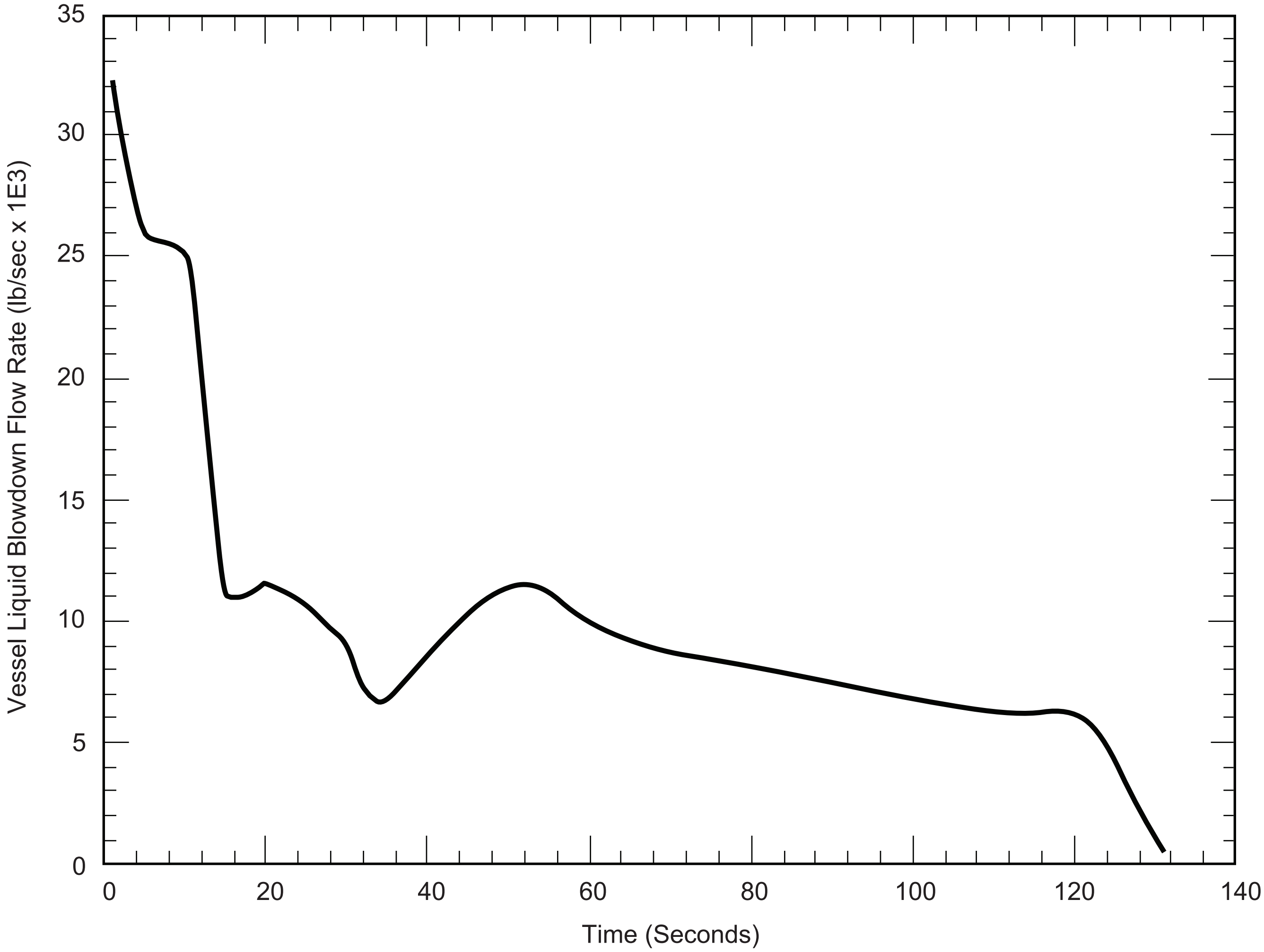
Draw. No. 920843.13 | Rev. | Figure 6.2-27

Upward Pressure Differential Across Bulkhead Plate from a 24 Inch Recirculation Line Break



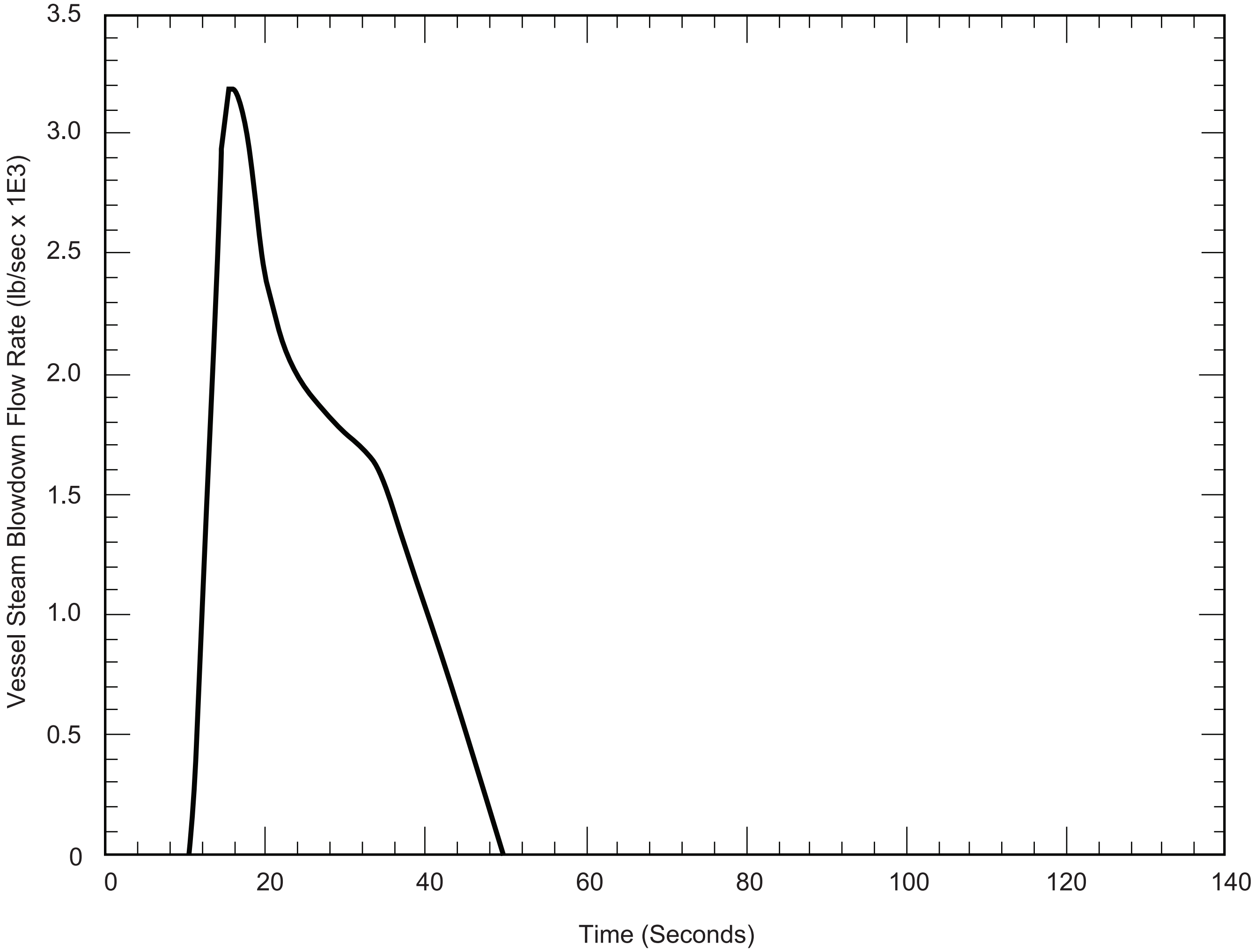
Upward Pressure Differential Across Bulkhead Plate from 24 In. Recirculation Line Break

Draw. No. 920843.14	Rev.	Figure 6.2-28

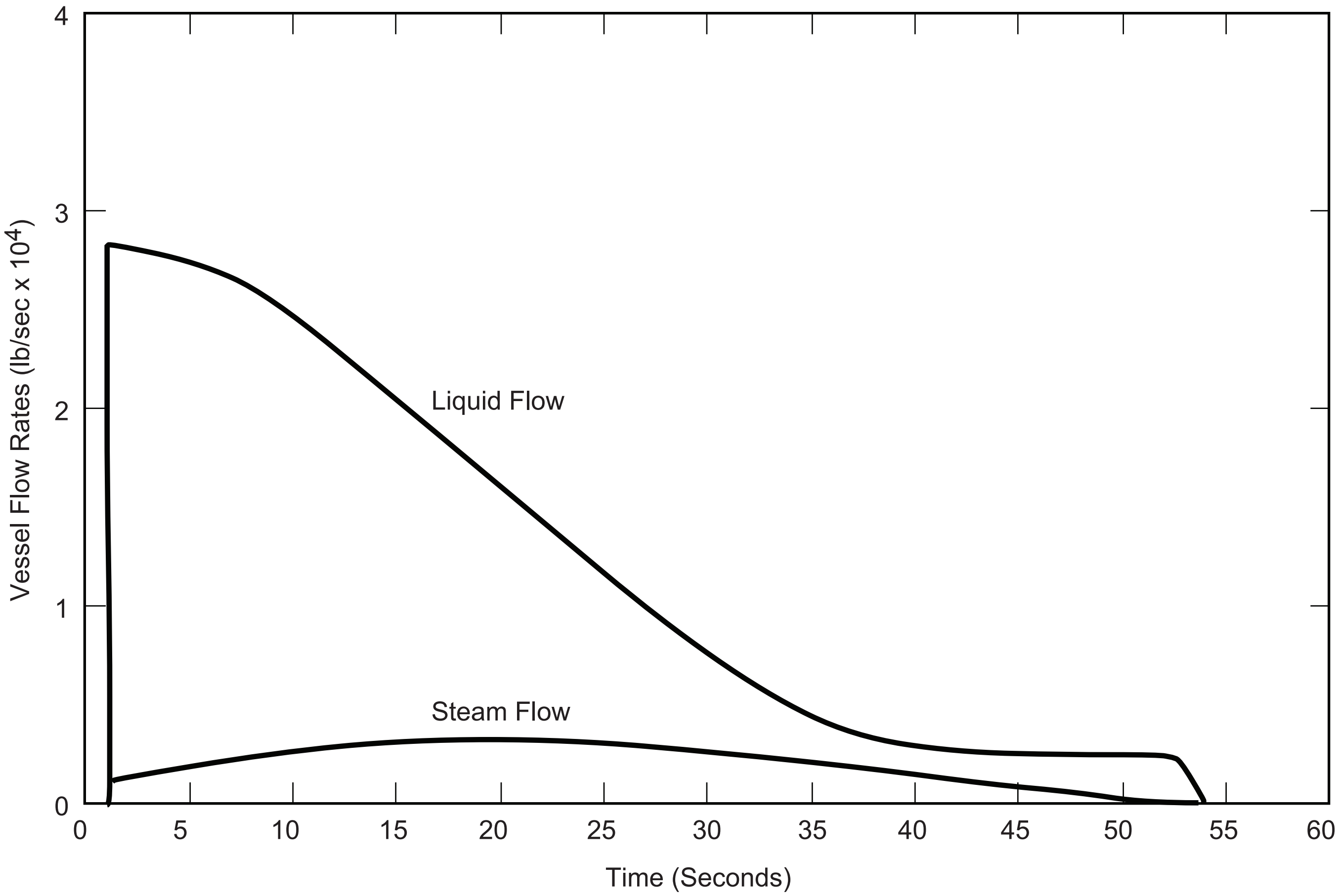


Recirculation Break Blowdown Flow Rates Liquid Flow - Short-Term Original Rated Power

Draw. No. 960222.10 | Rev. | Figure 6.2-29



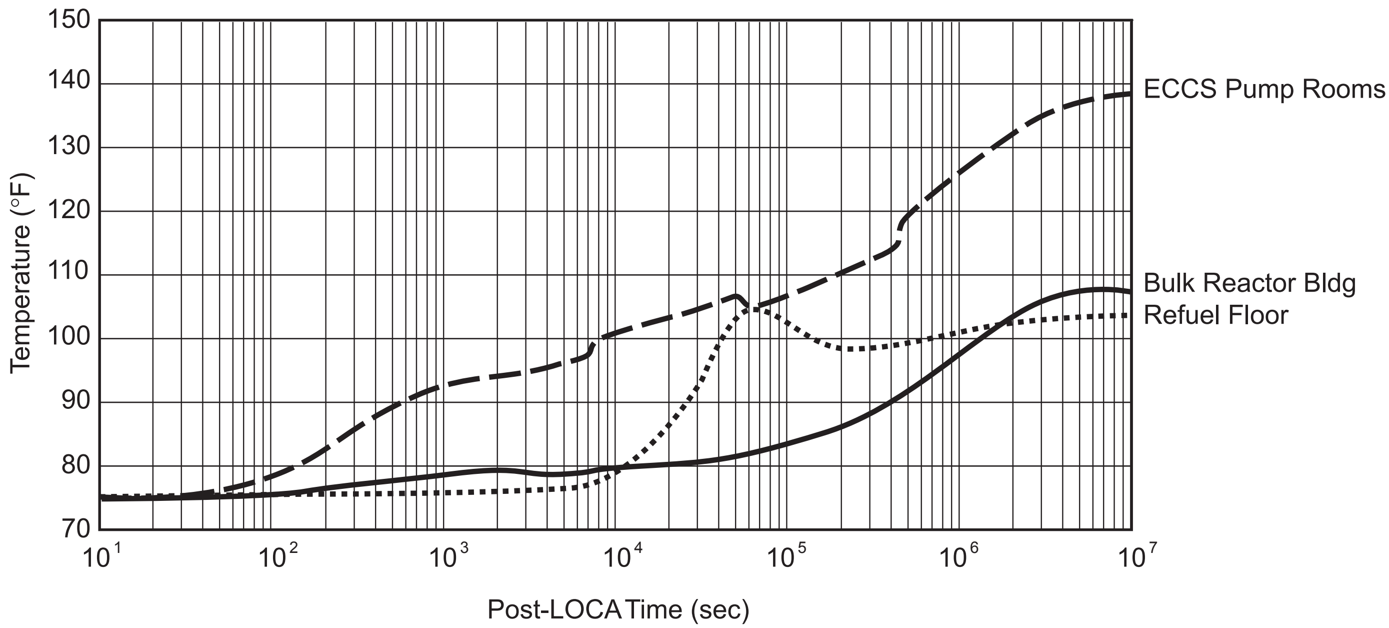
Columbia Generating Station **Final Safety Analysis Report**	**Recirculation Break Blowdown Flow Rates Steam Flow - Short-Term Original Rated Power**
	Draw. No. **960222.11** Rev. Figure **6.2-30**



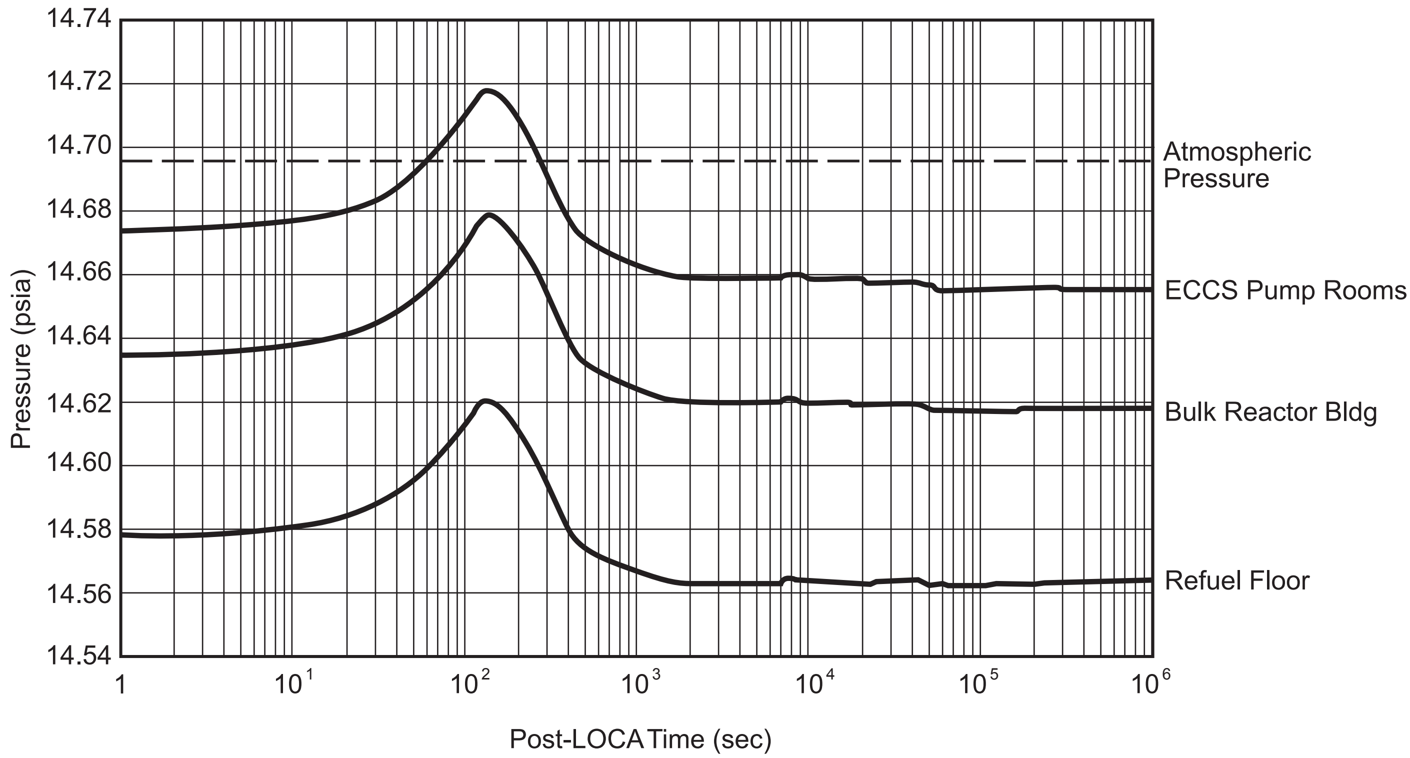
Columbia Generating Station
Final Safety Analysis Report

Main Steam Line Break Blowdown Flow Rates

Draw. No. 960222.36 | Rev. | Figure 6.2-31



Columbia Generating Station Final Safety Analysis Report	Long-Term Post-LOCA Secondary Containment Temperature Transient		
	Draw. No. 920843.17	Rev.	Figure 6.2-34



Columbia Generating Station Final Safety Analysis Report	Short-Term Post-LOCA Secondary Containment Pressure Transient		
	Draw. No. 920843.16	Rev.	Figure 6.2-35

Notes on Type C Testing (Isolation Valve Leakage Testing)

1. Type C testing is performed by applying a differential pressure in the same direction as seen by the valves during containment isolation.

2. Type C testing is performed by pressurizing between the two-piece disk gate valve.

3. Type C testing is performed by pressurizing between the isolation valves. The test yields conservative results since the inboard, globe valve is pressurized under the seat during the test; whereas, during containment isolation, it is pressurized above the seat.

4. Type C testing is performed by pressurizing between the isolation valves. The test yields equivalent results for the inboard gate or butterfly valve. *

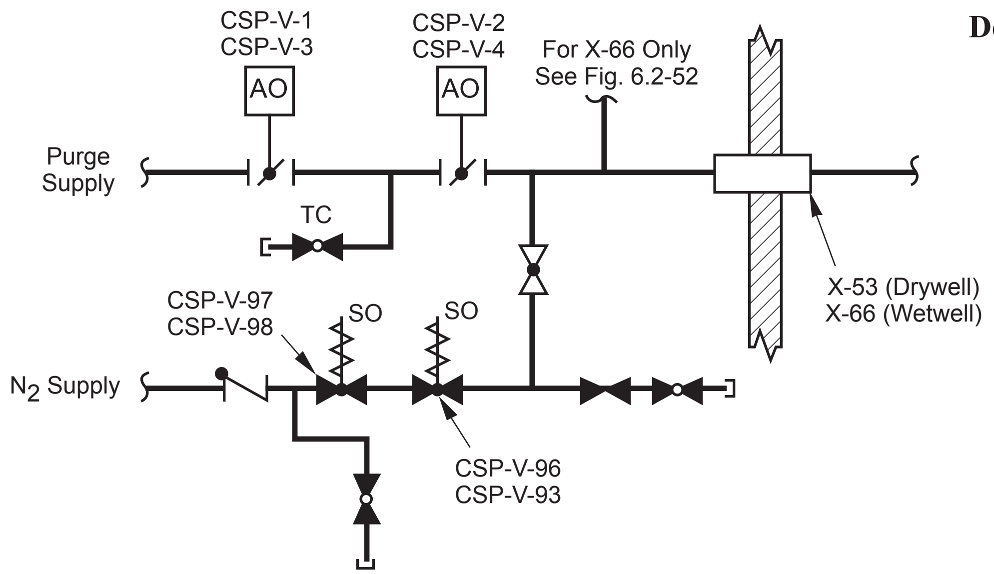
5. Type C testing is not required since a water seal is provided by the supression pool.

6. Type C testing is performed by pressurizing between the isolation valves. The test yields equivalent results for the inboard gate valve. * The one-inch globe valve will have test pressure applied under the seat; however, the difference between testing a one-inch globe valve over or under the seat is considered negligible.

7. Type C testing is performed by pressurizing between the isolation valves. The one-inch globe valve will have test pressure applied over the seat for the inboard isolation valve and under the seat for the outboard isolation valve. The difference between testing under and over the seat for a one-inch globe valve is considered negligible.

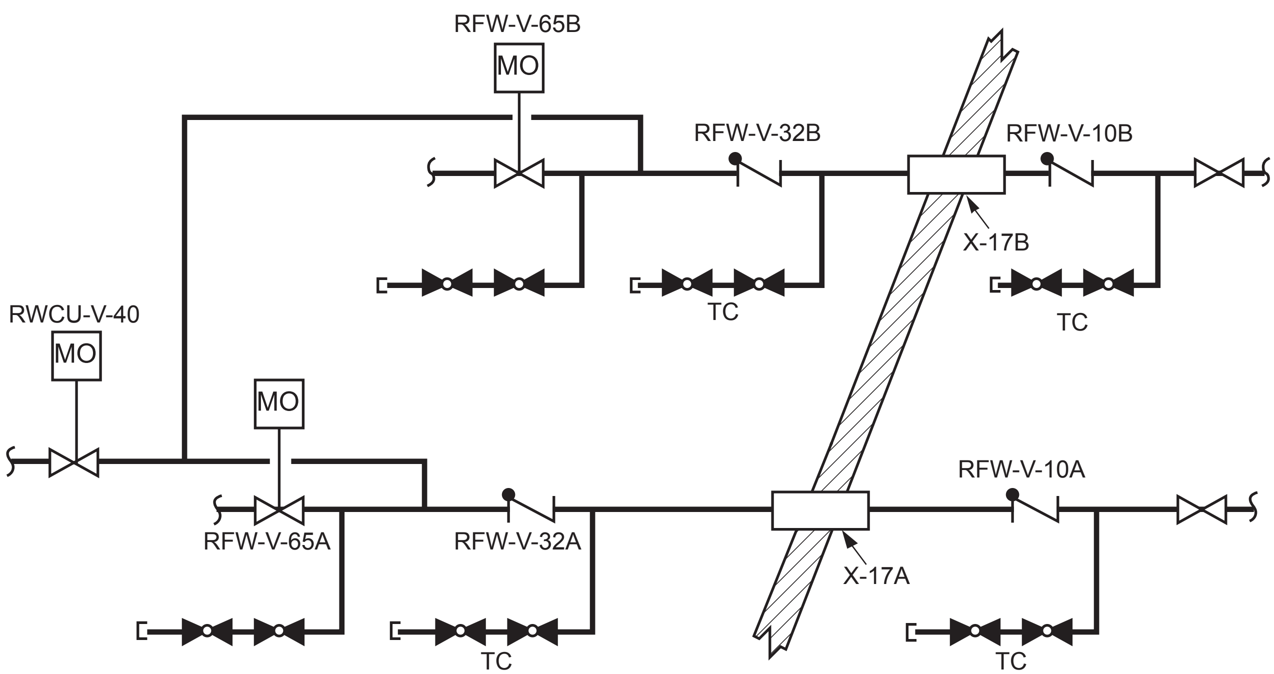
8. Type C testing is performed by pressurizing between the isolation valves. The one-inch globe valve will have test pressure applied under the seat; however, the difference between testing a one-inch globe valve over or under the seat is considered negligible.

* The gate and butterfly valves are because of symmetry of design and because of construction equally leak tight in either direction. This fact has been confirmed by review of leakage test data and other information supplied by the valve manufacturers.



Note: See Note 4 on Figure 6.2-36

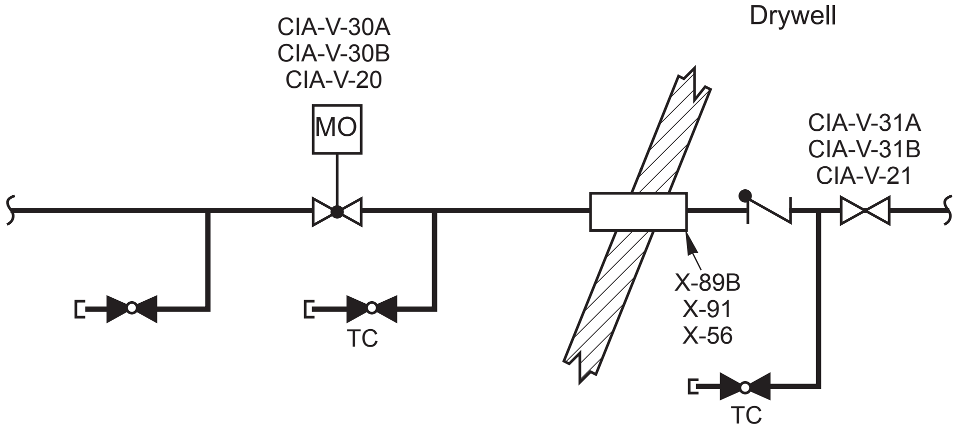
X-53 Drywell Purge and Inerting Makeup
X-66 Wetwell Purge and Inerting Makeup



Note: See Note 1 on Figure 6.2-36

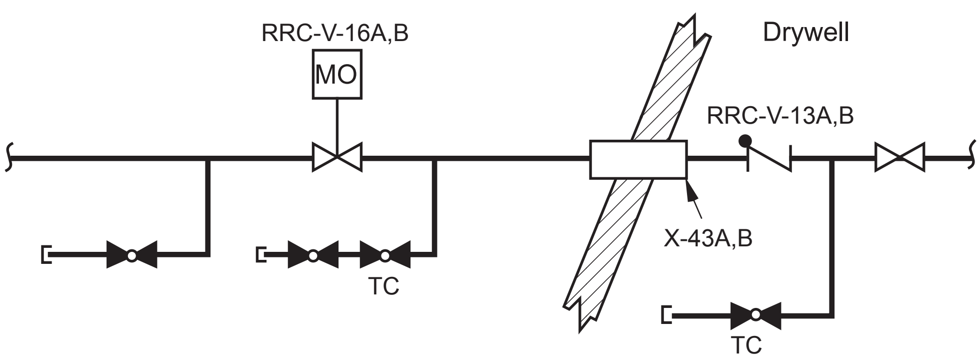
Reactor Feedwater Lines

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-53, X-66, X-17A and X-17B
	Draw. No. 920843.18	Rev.	Figure 6.2-37



Note: See Note 1 on Figure 6.2-36

Containment Instrument Air



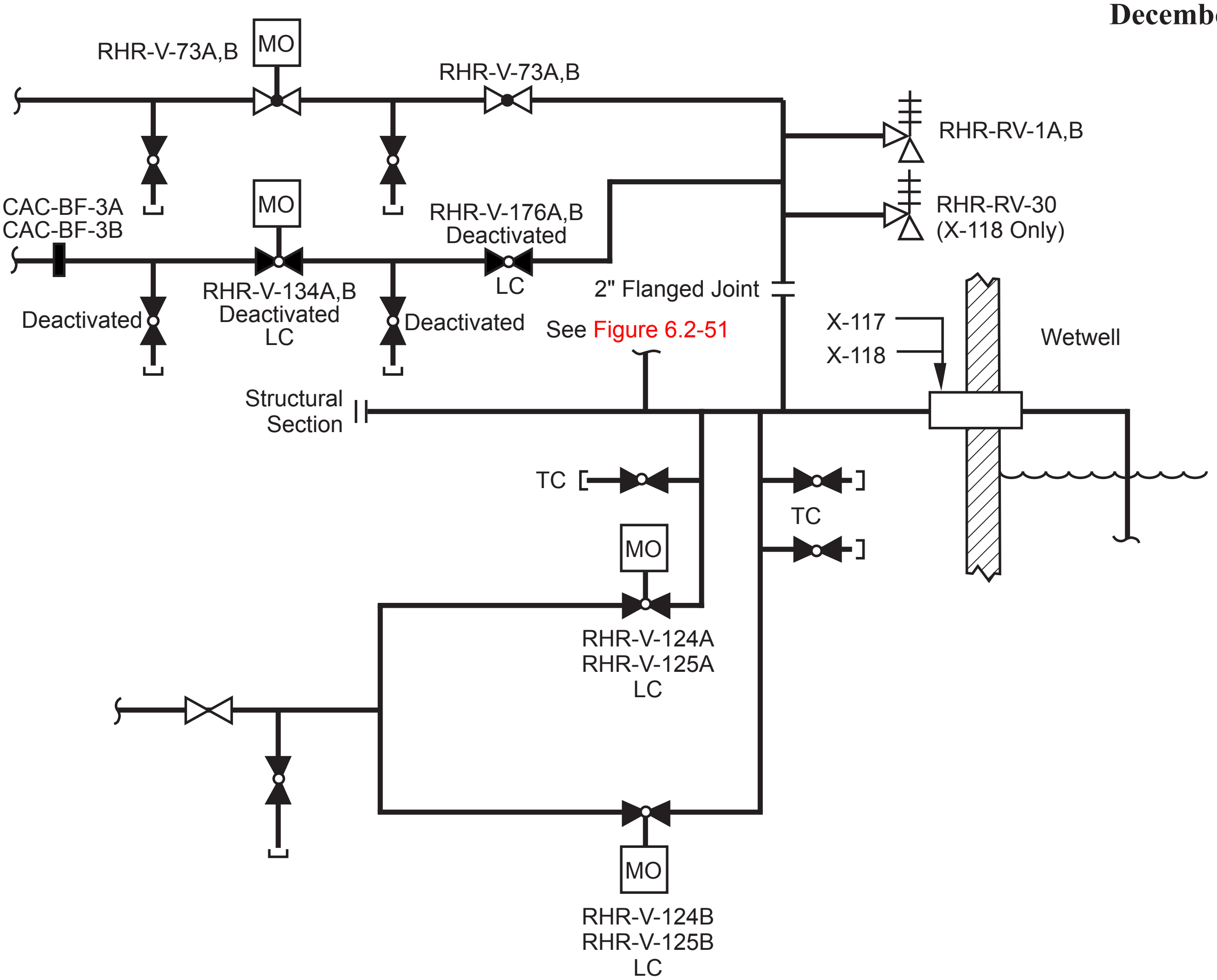
Note: See Note 1 on Figure 6.2-36

RRC Pump Seal Purge

Columbia Generating Station
Final Safety Analysis Report

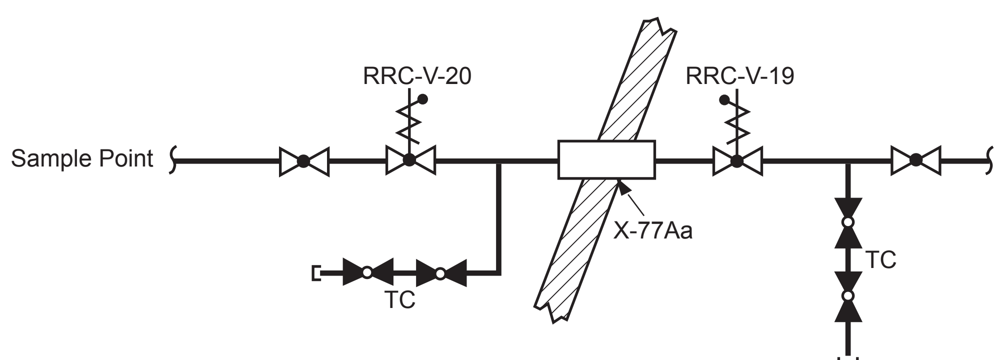
Isolation Valve Arrangement for Penetrations X-89B, X-91, X-56, X-43A, and X-43B

Draw. No. 920843.19 | Rev. | Figure 6.2-38



RHR Steam Lines

Note: See Note 5 on Figure 6.2-36

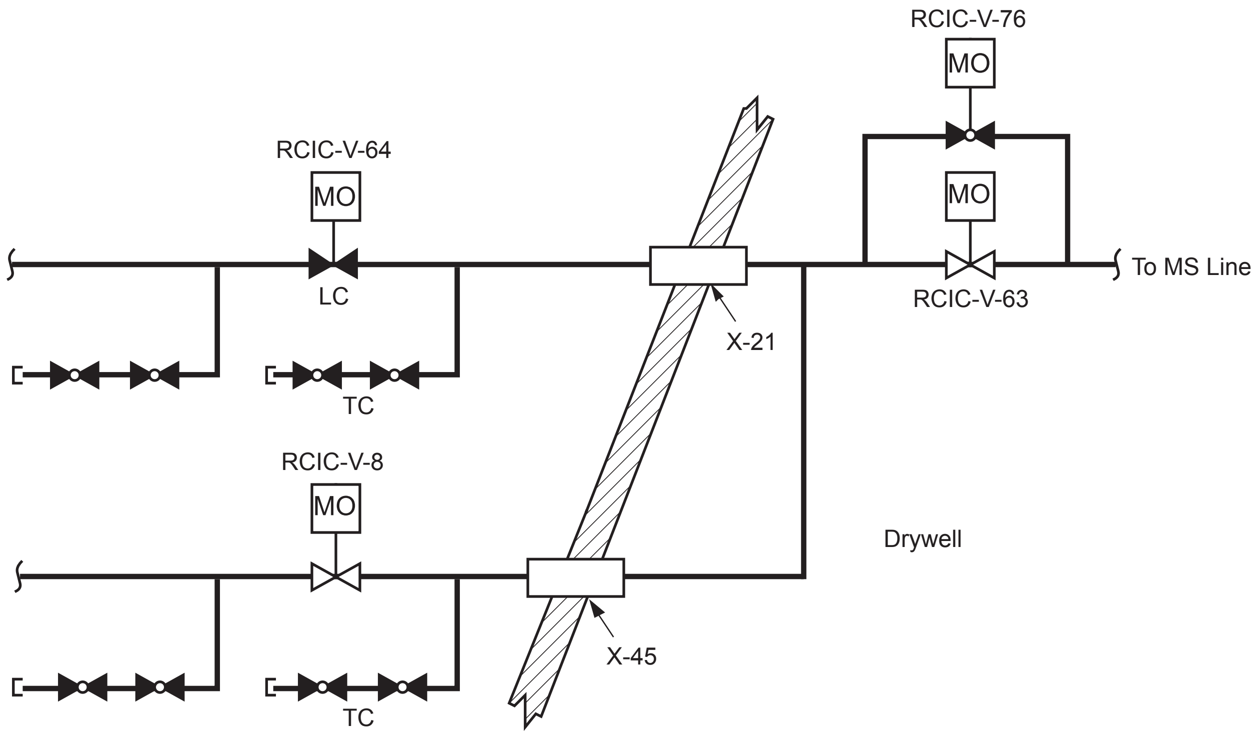


Note: See Note 1 on Figure 6.2-36

RCC Sample Line

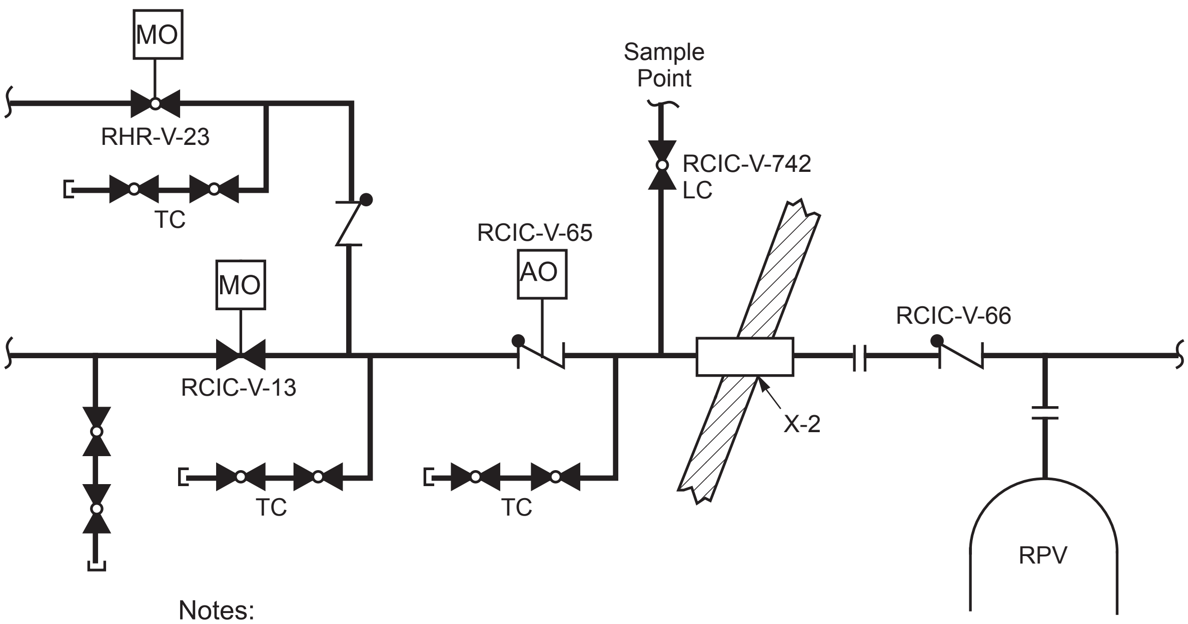
Columbia Generating Station Final Safety Analysis Report	**Isolation Valve Arrangement for Penetrations X-117, X-118 and X-77Aa**	
	Draw. No. 920843.21	Rev.
		Figure 6.2-39

Form No. 960690FH
LDCN-08-028



Note: See Note 6 on Figure 6.2-36

Steam to RCIC Turbine and RHR Heat Exchanger

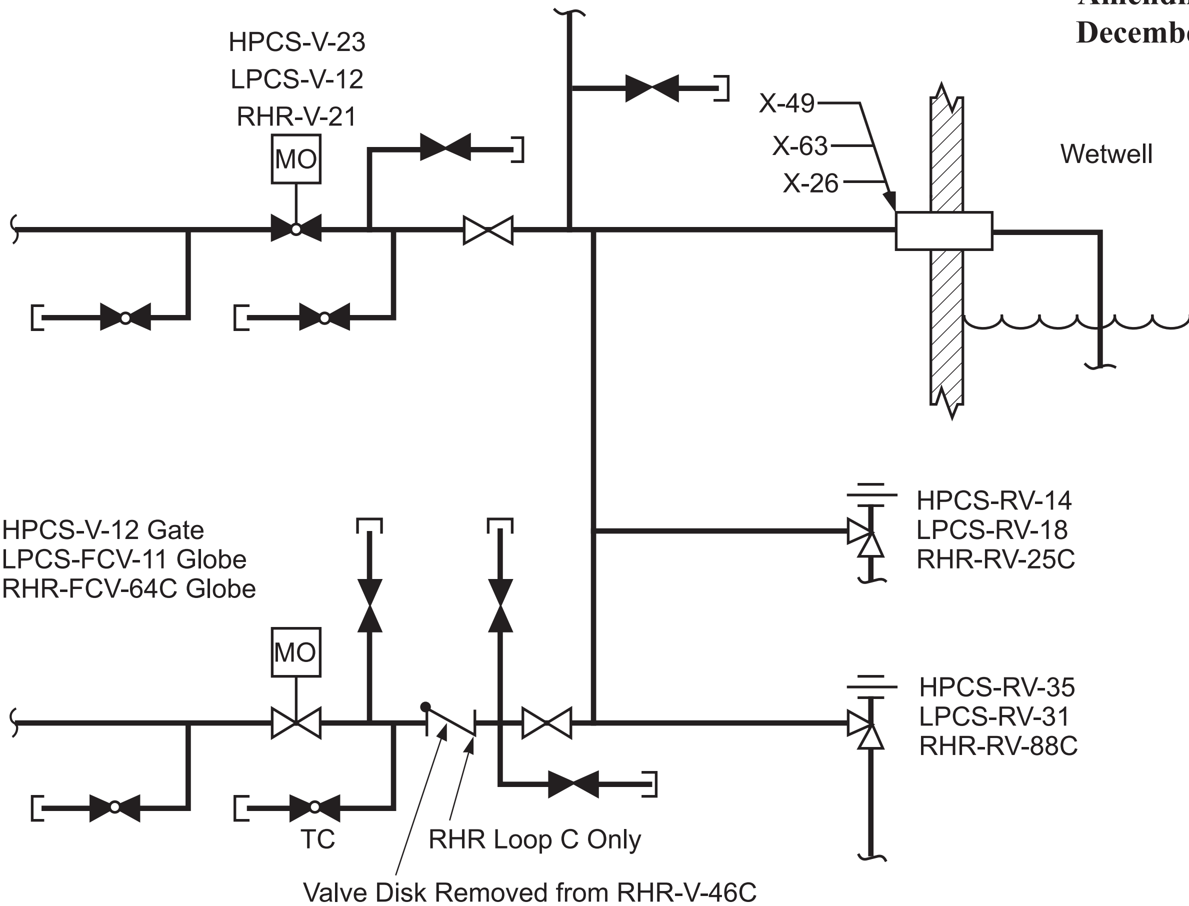


Notes:

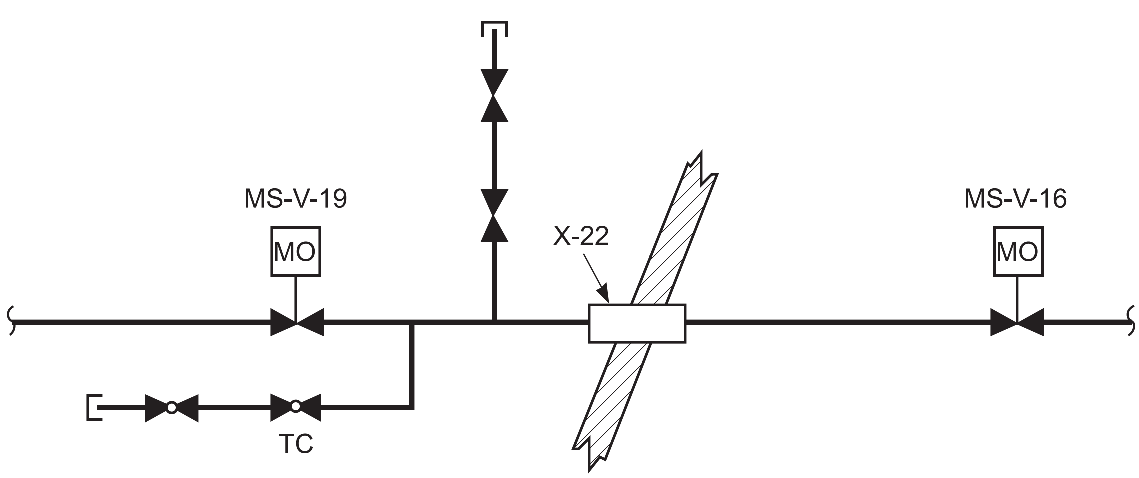
RCIC-V-66 will be "bench tested" once the line is removed for refueling.
RHR-V-23 and RCIC-V-13 can be tested once the flanged connection is blanked off as per note 1 on figure 6.2-36

RCIC/RHR Head Spray

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-21, X-45 and X-2		
	Draw. No. 920843.22	Rev.	Figure 6.2-40



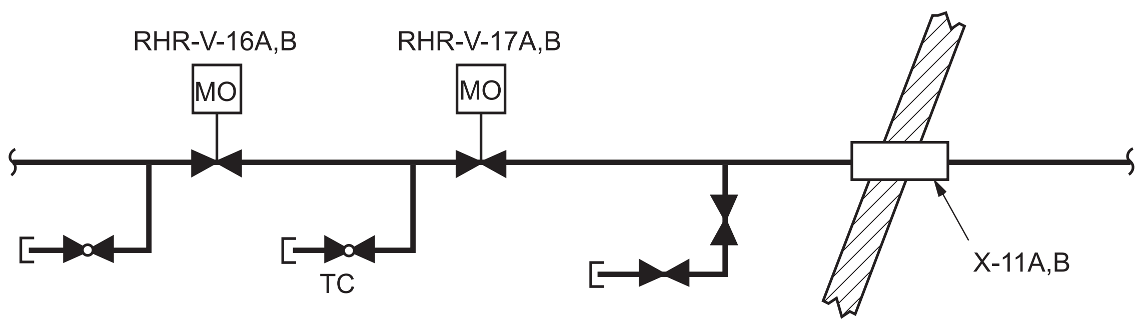
Note: See Note 5 on Figure 6.2-36
X-49 HPCS Test Line
X-63 LPCS Test Line
X-26 RHR Loop C Test Line



Note: See Note 4 on Figure. 6.2-36

MS Drain Line

Columbia Generating Station **Final Safety Analysis Report**	**Isolation Valve Arrangement for Penetrations X-49, X-63, X-26 and X-22**
	Draw. No. 950021.13 | Rev. | Figure 6.2-41



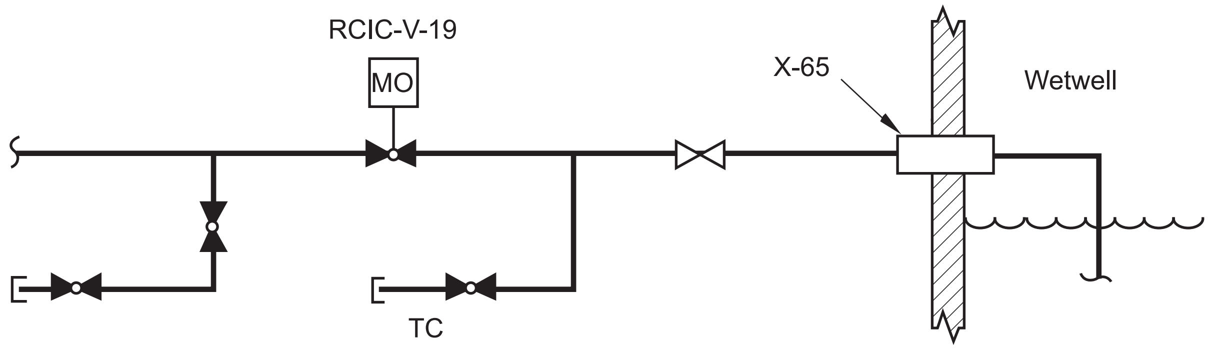
Note: See Note 4 on Figure 6.2-36

RHR Drywell Spray

Columbia Generating Station
Final Safety Analysis Report

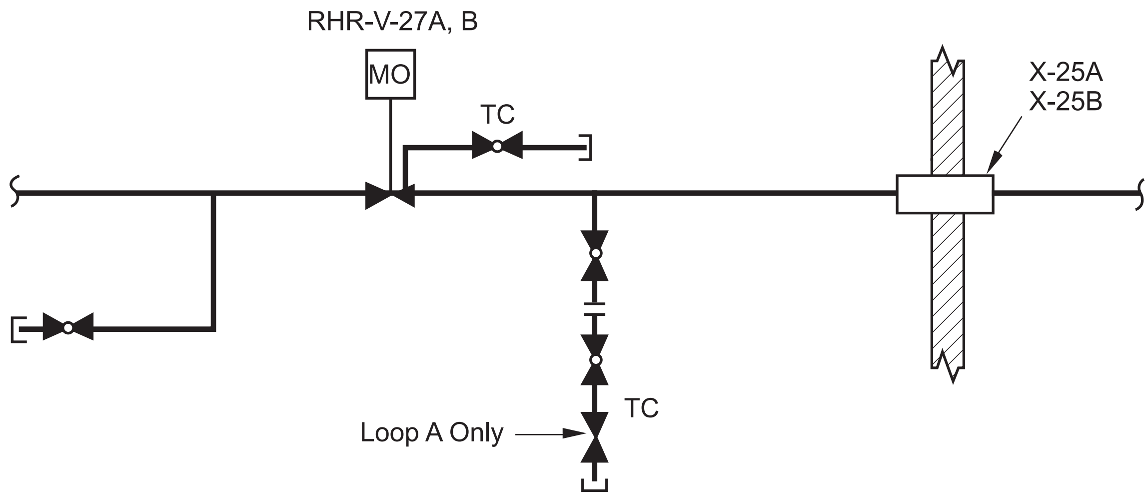
Isolation Valve Arrangement for Penetrations X-11A and X-11B

Draw. No. 920843.08	Rev.	Figure 6.2-42



Note: See Note 5 on Figure 6.2-36

RCIC Pump Min. Flow



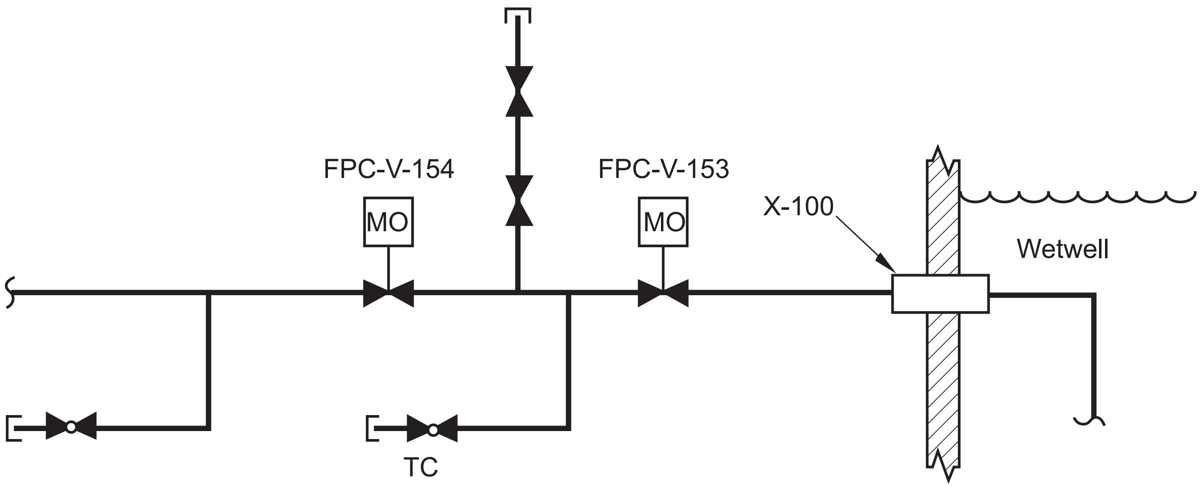
Note: See Note 2 on Figure 6.2-36

RHR Wetwell Spray

Columbia Generating Station
Final Safety Analysis Report

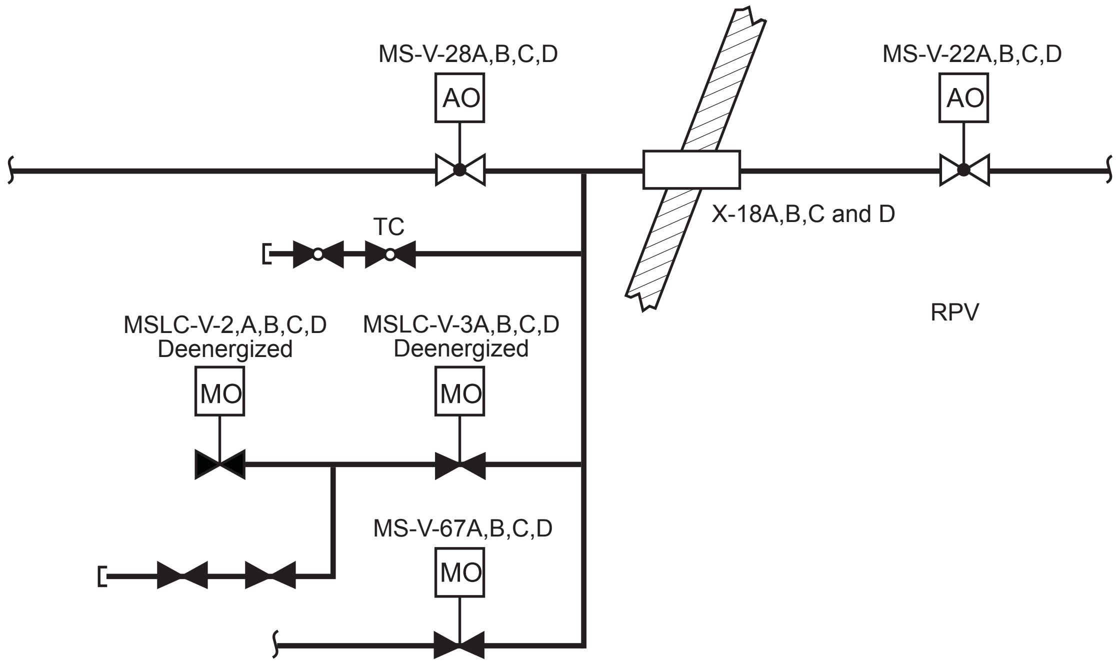
Isolation Valve Arrangement for Penetrations X-65, X-25A and X-25B

Draw. No. 920843.09 | Rev. | Figure 6.2-43



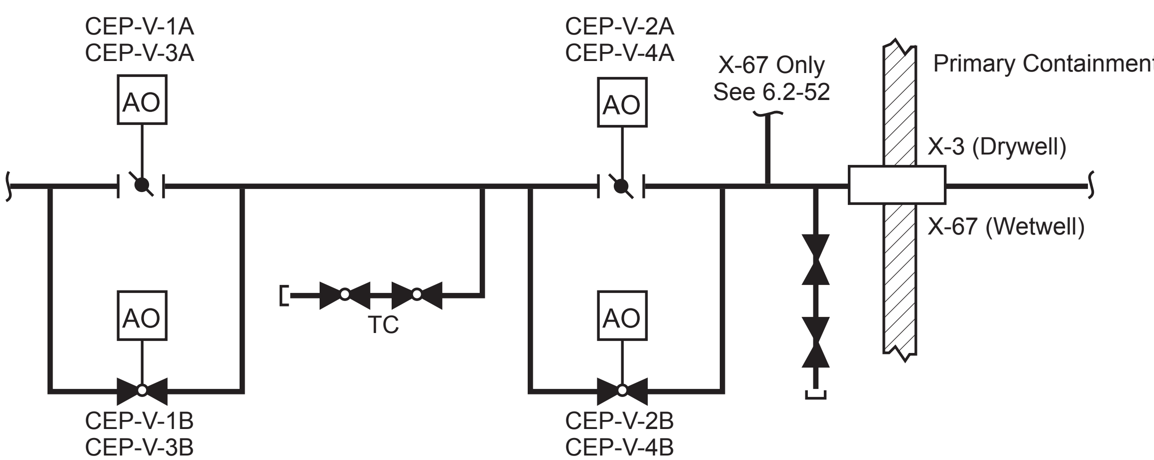
Note: See Note 4 on Figure 6.2-36

Suppression Pool Cleanup Suction Line



Note: See Note 3 on Figure 6.2-36

Main Steamlines



Note: See Note 4 on Figure 6.2-36

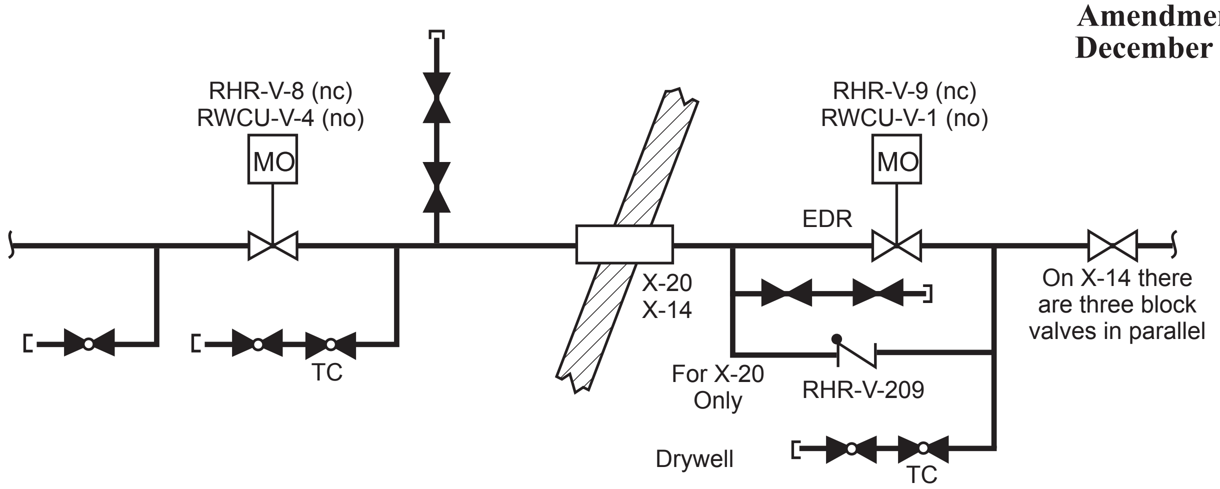
X-3 Drywell Purge Exhaust

X-67 Wetwell Purge Exhaust

Columbia Generating Station
Final Safety Analysis Report

Isolation Valve Arrangement for Penetrations X-18A, X-18B, X-18C, X18D, X-3 and X-67

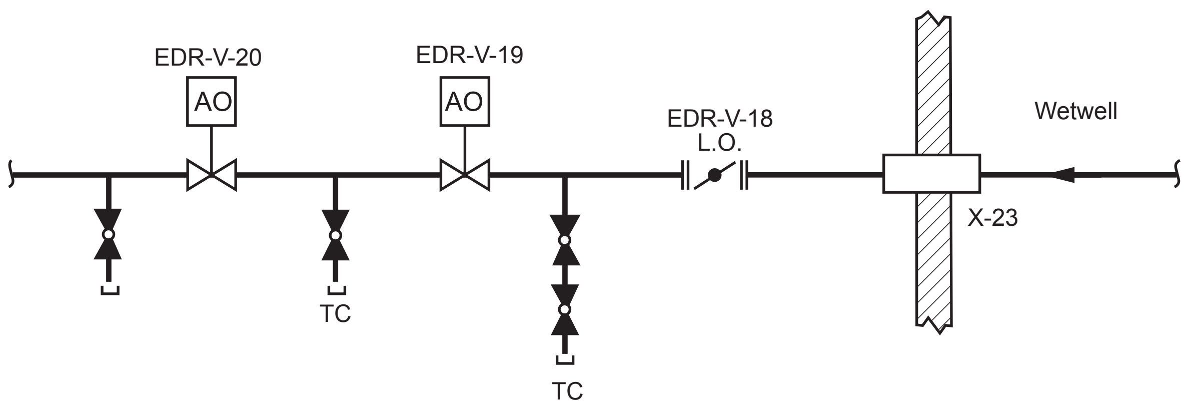
Draw. No. 920843.23	Rev.	Figure 6.2-45



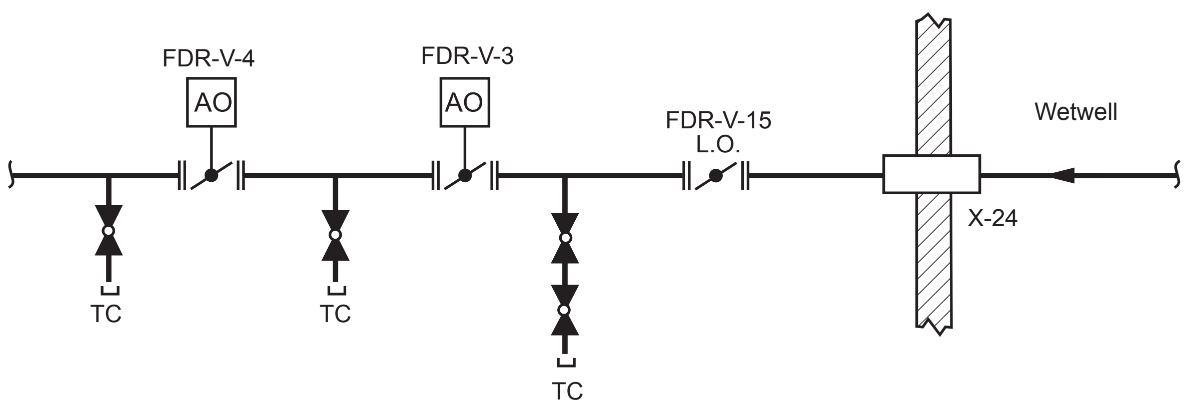
Note: See Notes 1 (X-20 Only), and 4 (X-14 Only) on Figure 6.2-36

X-20 RHR Shutdown Cooling Supply

X-14 RWCU Suction



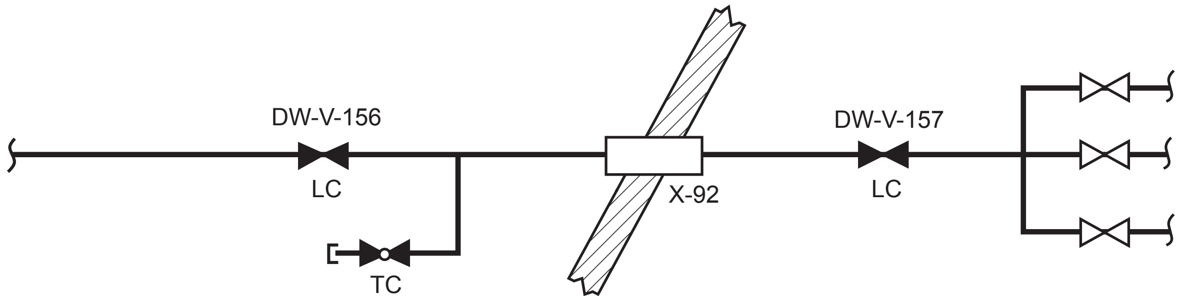
X-23 EDR from Primary Containment



X-24 FDR from Primary Containment

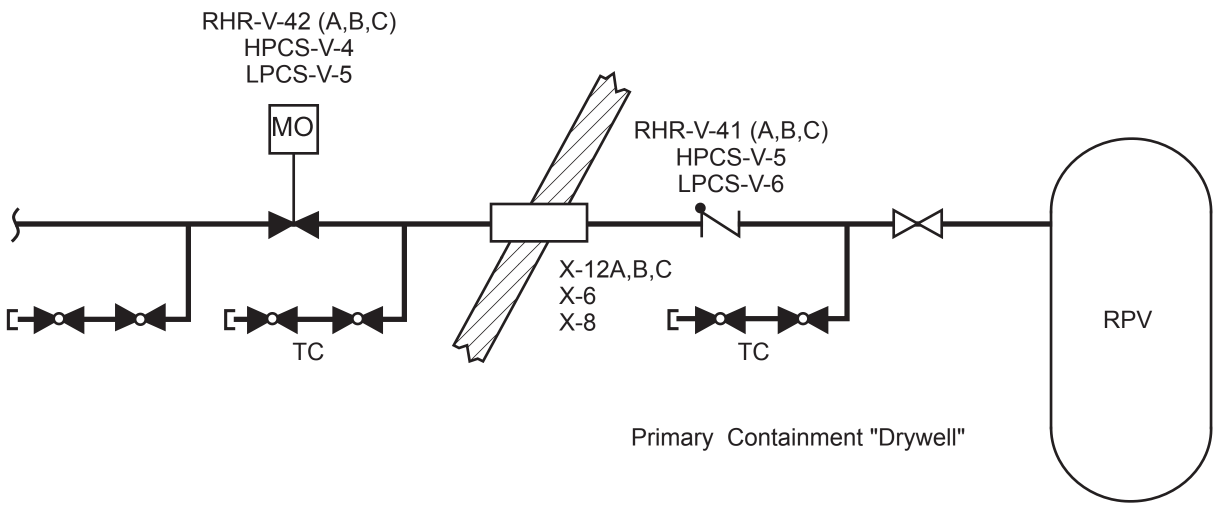
Note: See Note 1 on Figure 6.2-36 for X-23 And X-24

Columbia Generating Station **Final Safety Analysis Report**	**Isolation Valve Arrangement for Penetrations X-20, X-14, X-23 and X-24**
	Draw. No. 920843.24 | Rev. | Figure 6.2-46



Note: See Note 4 on Figure 6.2-36

DW System



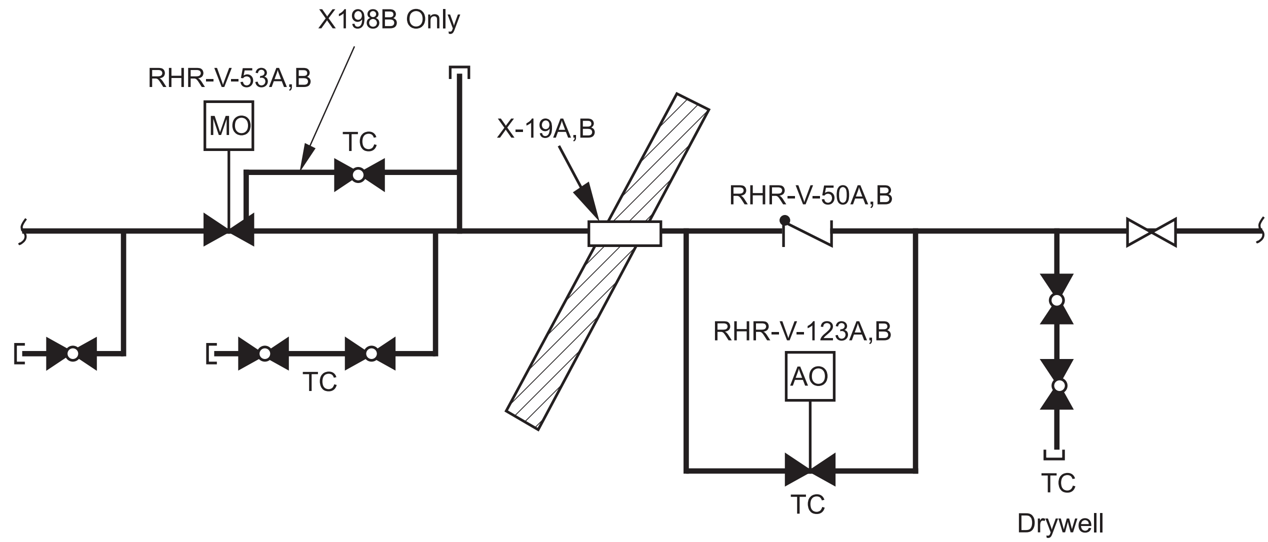
Note: See Note 1 on Figure 6.2-36

X-12A RHR Loop A LPCI to RPV
X-12B RHR Loop B LPCI to RPV
X-12C RHR Loop C LPCI to RPV
X-6 HPCS to RPV
X-8 LPCS to RPV

Columbia Generating Station
Final Safety Analysis Report

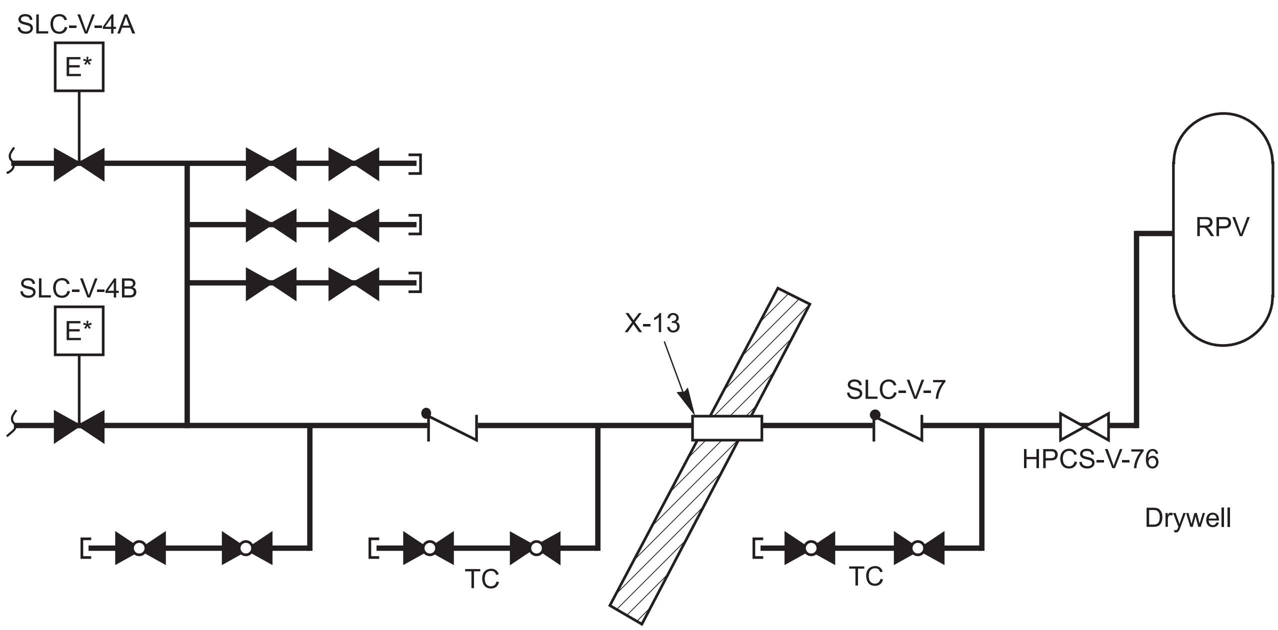
Isolation Valve Arrangement for Penetrations X-92, X-12A, X-12B, X-12C, X-6 and X-8

Draw. No. 920843.25	Rev.	Figure 6.2-47



Note: See Note 2 on Fig. 6.2-36

RHR SHUTDOWN COOLING RETURN

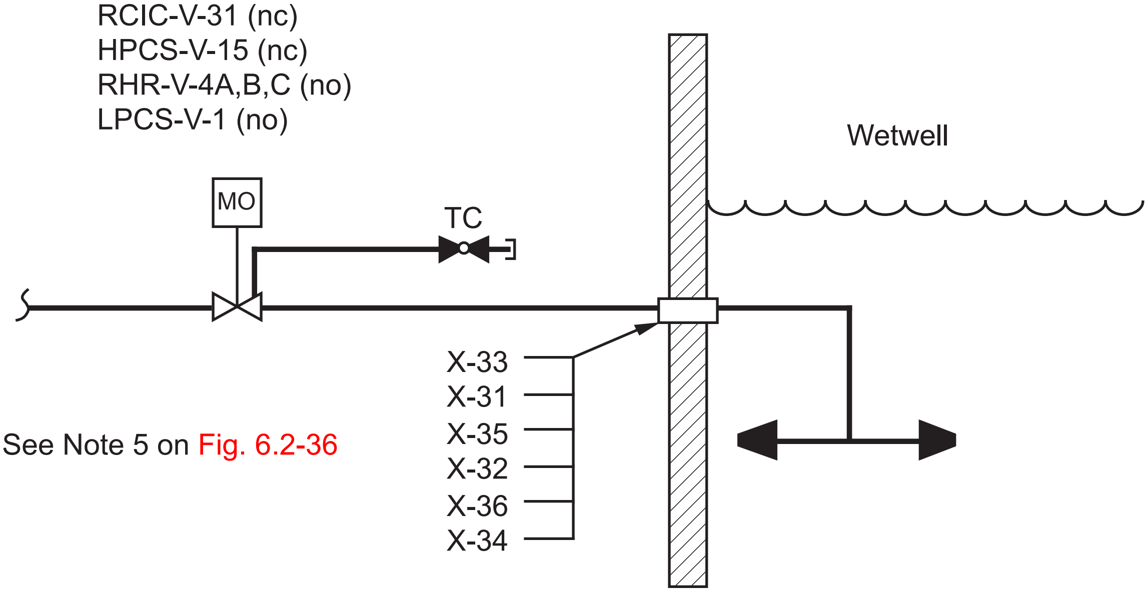


*Explosive Actuated Valve

Note: See Note 2 on Fig. 6.2-36

SLC SYSTEM INJECTION LINE

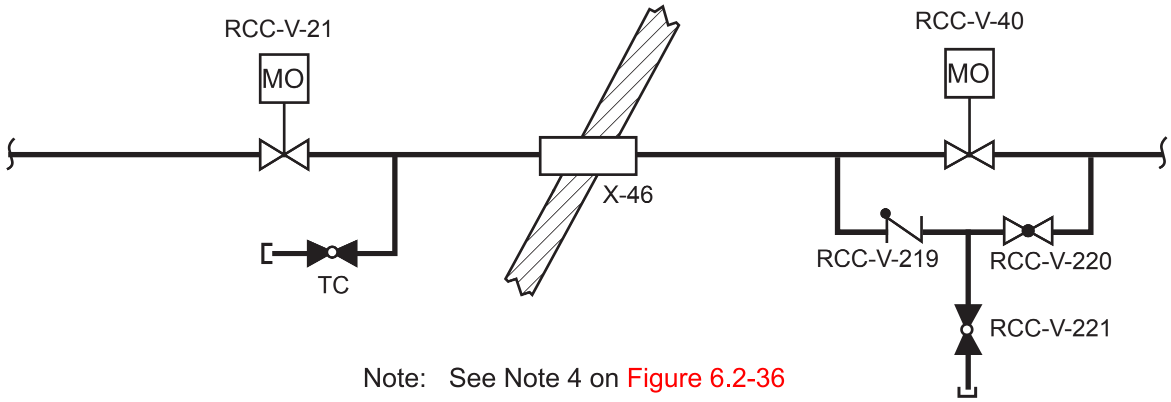
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-19A, X-19B and X-13		
	Draw. No. 900547.31	Rev.	Figure 6.2-48



Note: See Note 5 on Fig. 6.2-36

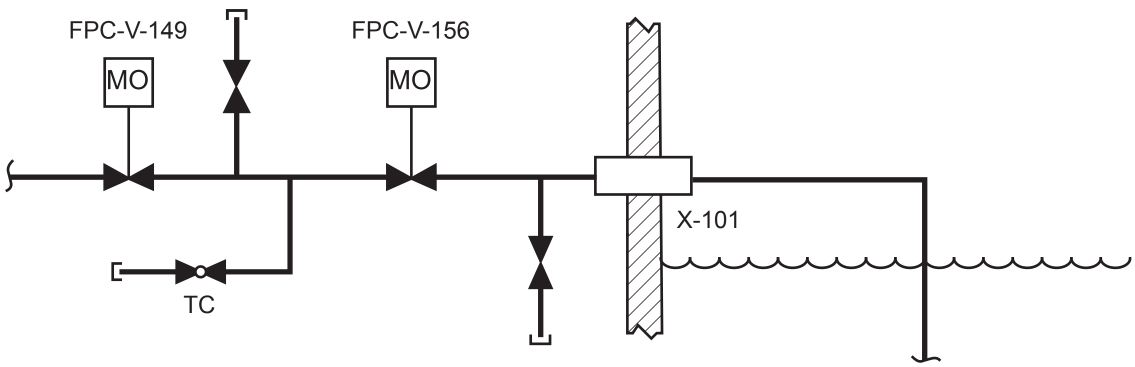
X-33 RCIC Pump Suction from Suppression Pool
X-31 HPCS Pump Suction from Suppression Pool
X-35 RHR"A" Pump Suction from Suppression Pool
X-32 RHR"B" Pump Suction from Suppression Pool
X-36 RHR"C" Pump Suction from Suppression Pool
X-34 LPCS Pump Suction from Suppression Pool

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-33, X-31, X-35, X-32, X-36 and X-34
	Draw. No. 920843.04 | Rev. | Figure 6.2-49



Note: See Note 4 on Figure 6.2-36

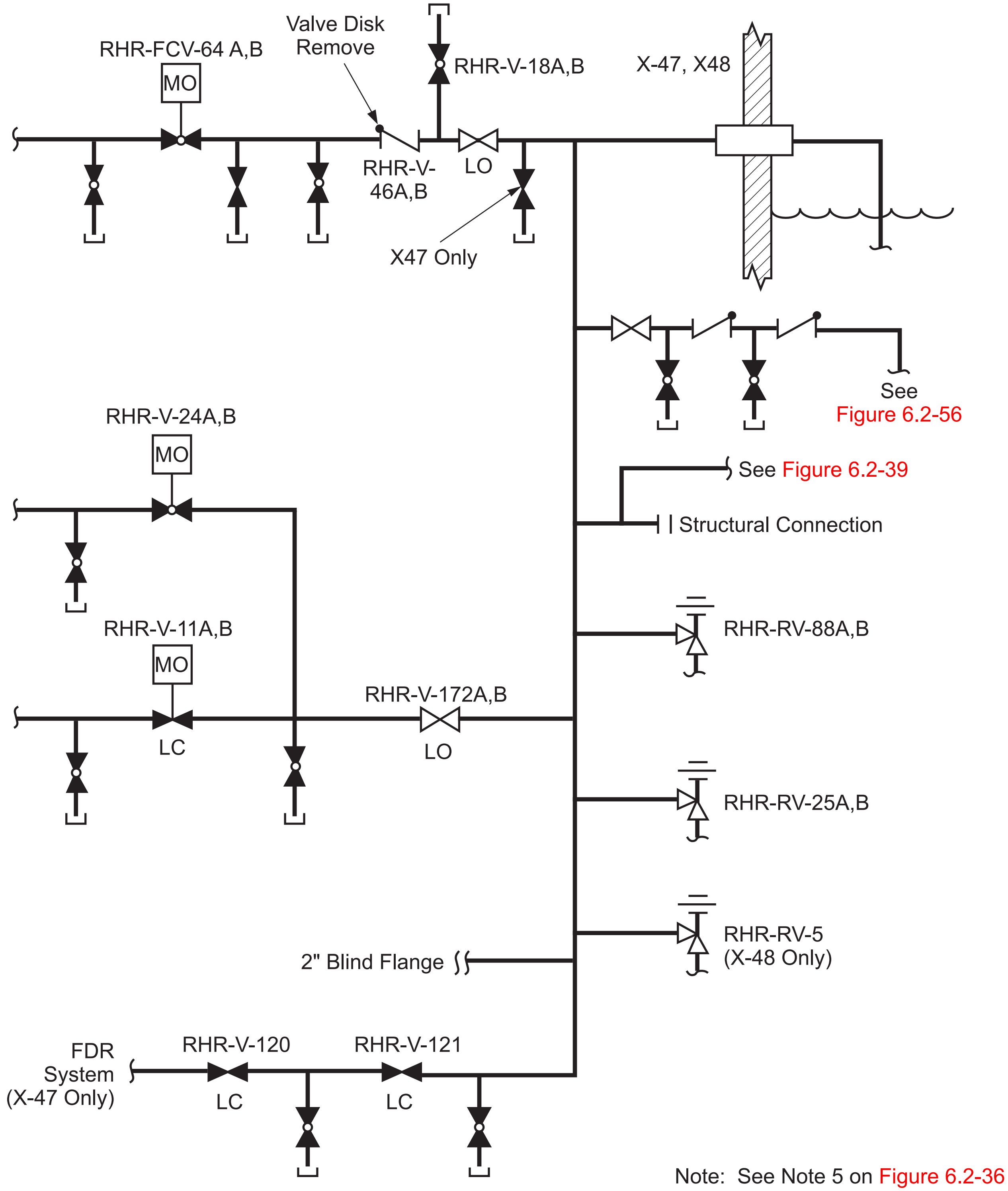
RCC Return Line



Note: See Note 4 on Figure 6.2-36

Suppression Pool Cleanup Return Line

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-46 and X-101		
	Draw. No. 920843.26	Rev.	Figure 6.2-50

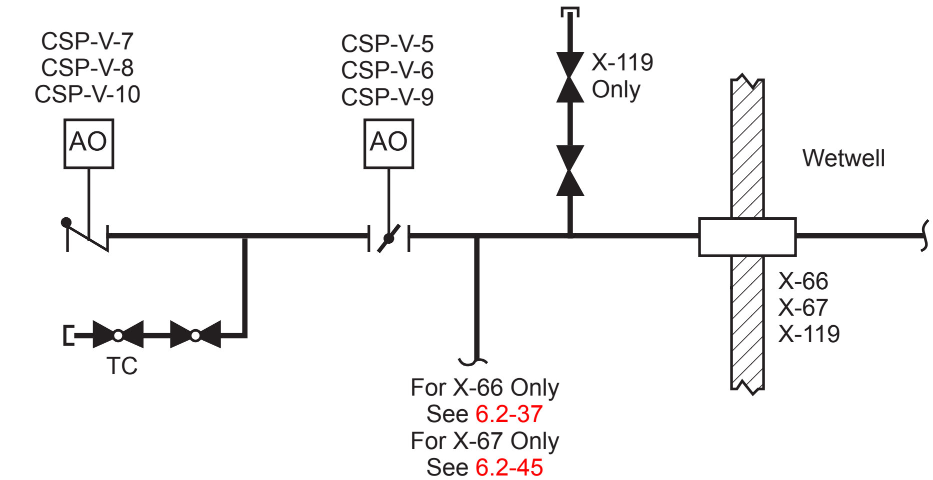


RHR Combined Return Line to Suppression Pool

Columbia Generating Station
Final Safety Analysis Report

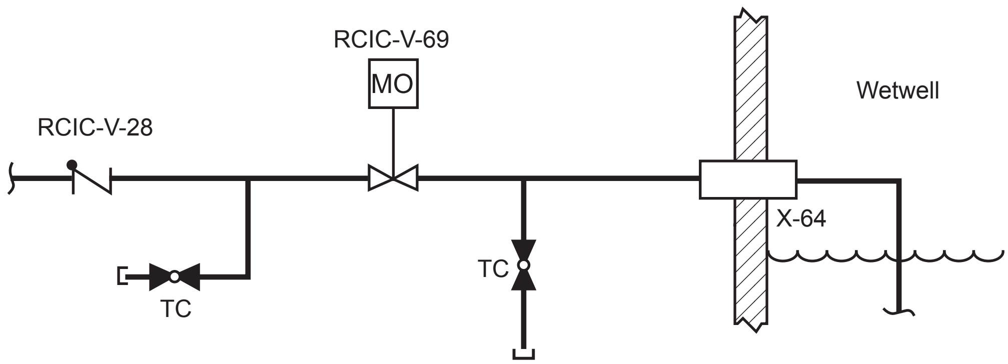
Isolation Valve Arrangement for Penetrations X-47 and X-48

Draw. No. 950021.14 | Rev. | Figure 6.2-51



Note: See Note 4 on Figure 6.2-36

Reactor Building To Wetwell Vacuum Relief



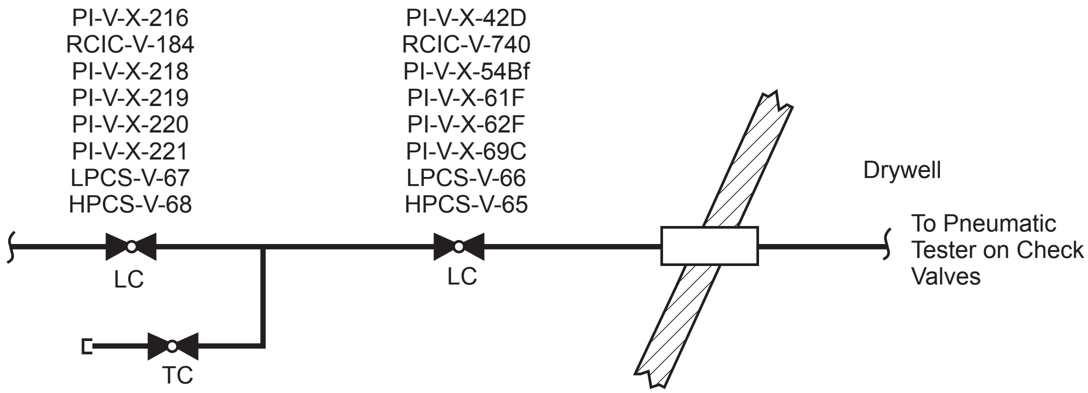
Note: See Note 5 on Figure 6.2-36

RCIC Vacuum Pump Discharge

Columbia Generating Station
Final Safety Analysis Report

Isolation Valve Arrangement for Penetrations X-66, X-67, X-119, X-64

Draw. No. 920843.27	Rev.	Figure 6.2-52



Note: See Note 7 on Figure 6.2-36

X-42D Air Line for RHR-V-50A

X-54Aa Spare Air Line

X-54Bf Air Line for RHR-V-41B

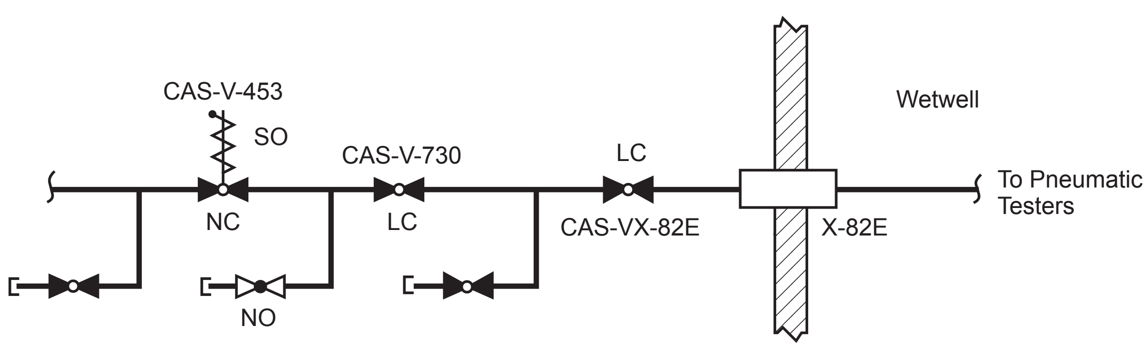
X-61F Air Line for RHR-V-41A

X-62F Air Line for RHR-V-41C

X-69C Air Line for RHR-V-50B

X-78D Air Line for LPCS-V-6

X-78E Air Line for HPCS-V-5



Note: See Note 8 on Figure 6.2-36

N_2/Air Supply for Testing Wetwell to Drywell Vacuum Breakers

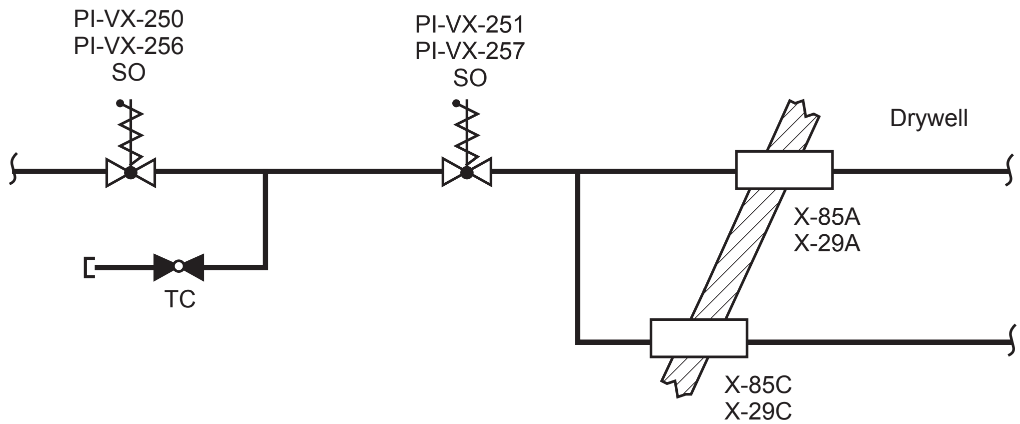
Columbia Generating Station
Final Safety Analysis Report

Isolation Valve Arrangement for Penetrations X-42D, 54Aa, 54Bf, 61F, 62F, 69C, 78D, 78E and 82E,

Draw. No. 920843.28	Rev.	Figure 6.2-53

Form No. 960690

LDCN-00-013

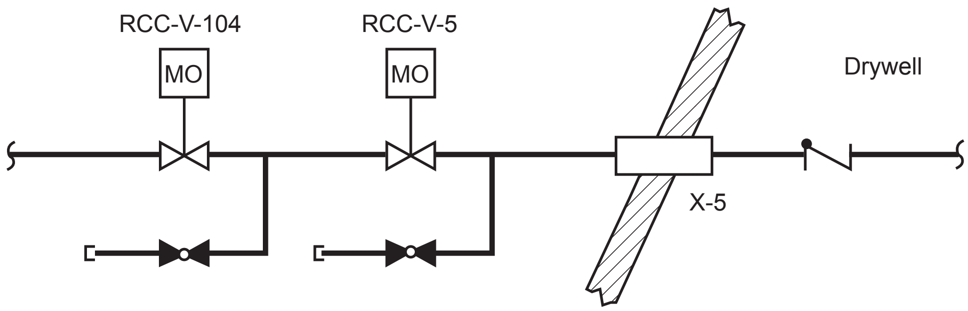


Note: See Note 1 on Figure 6.2-36

Radiation Monitor Supply Line Division A
Radiation Monitor Supply Line Division B

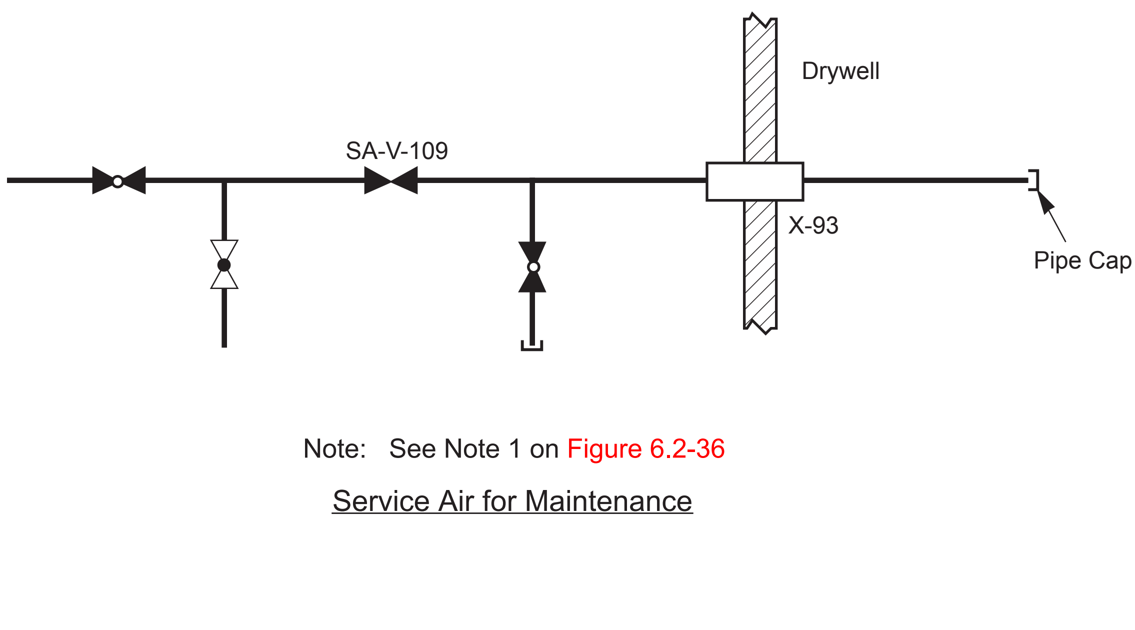
Note: See Note 1 on Figure 6.2-36

Radiation Monitor Return Line Division A
Radiation Monitor Return Line Division B



Note: See Note 4 on Figure 6.2-36

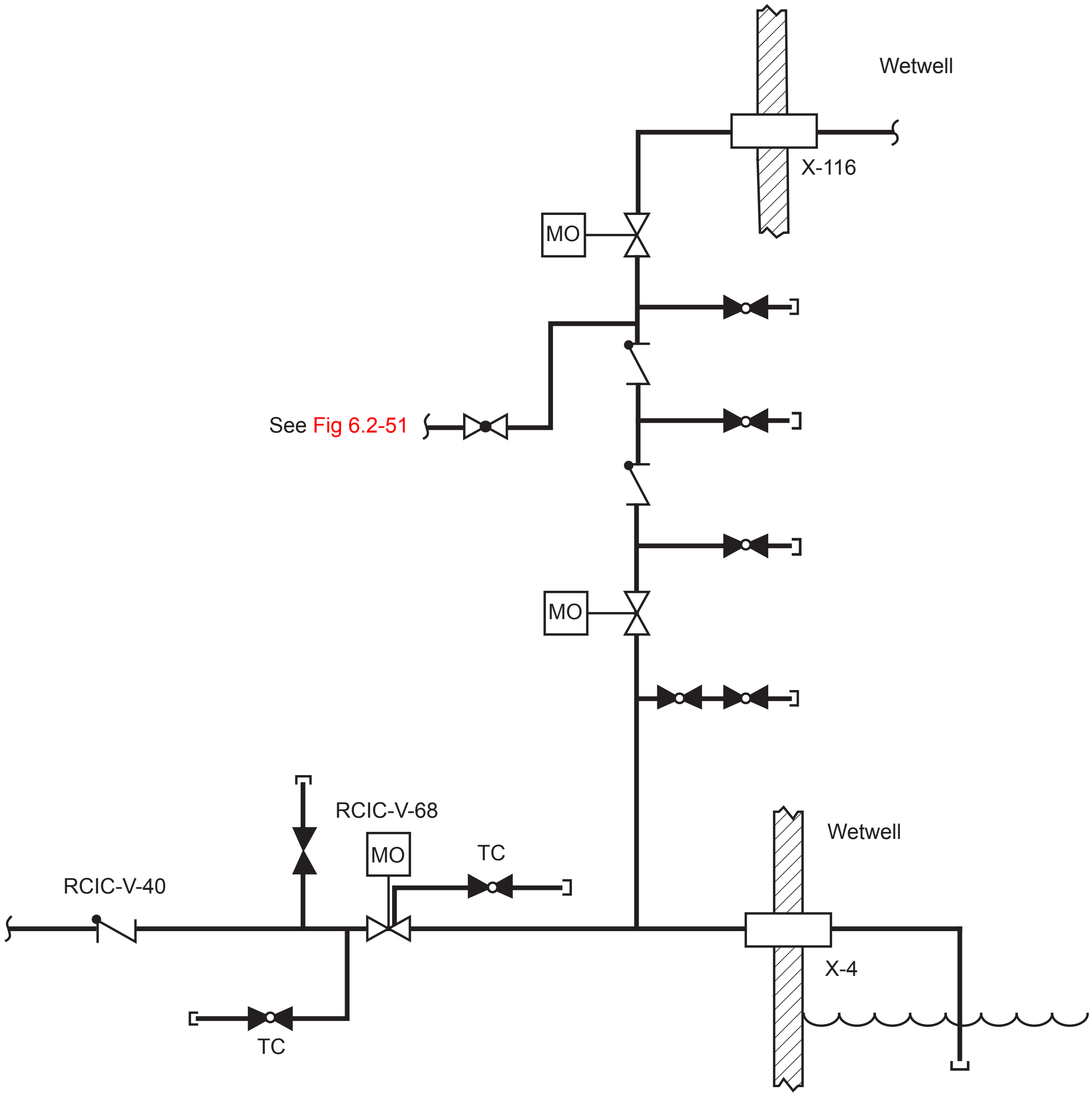
RCC Supply Line



Note: See Note 1 on Figure 6.2-36

Service Air for Maintenance

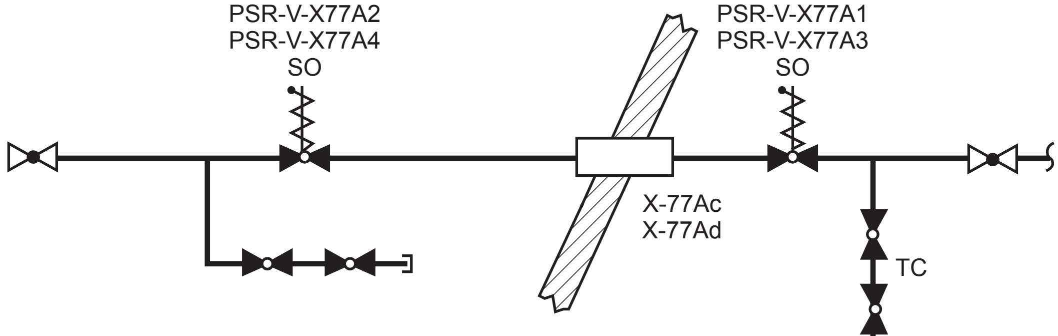
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-5 and X-93		
	Draw. No. 920843.30	Rev.	Figure 6.2-55



Note: See Note 4 on Figure 6.2-36

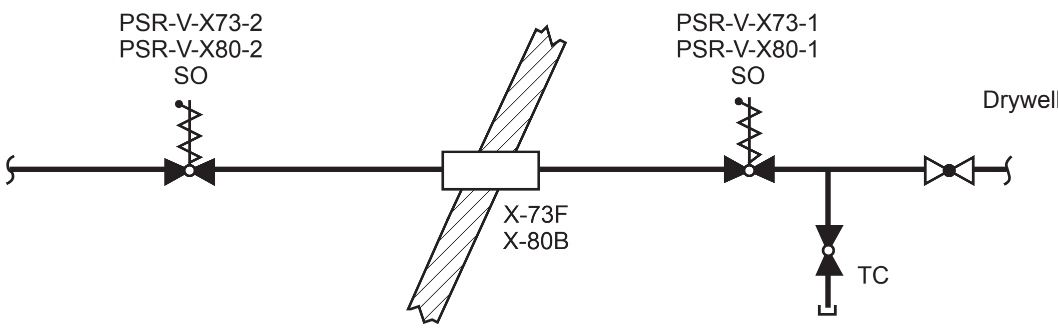
RCIC Turbine Exhaust and
Turbine Exhaust Vacuum Breaker

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-4 and X-116		
	Draw. No. 920843.31	Rev.	Figure 6.2-56



Note: See Note 1 on Figure 6.2-36

X-77Ac Jet Pump #10 Sample Line
X-77Ad Jet Pump #20 Sample Line



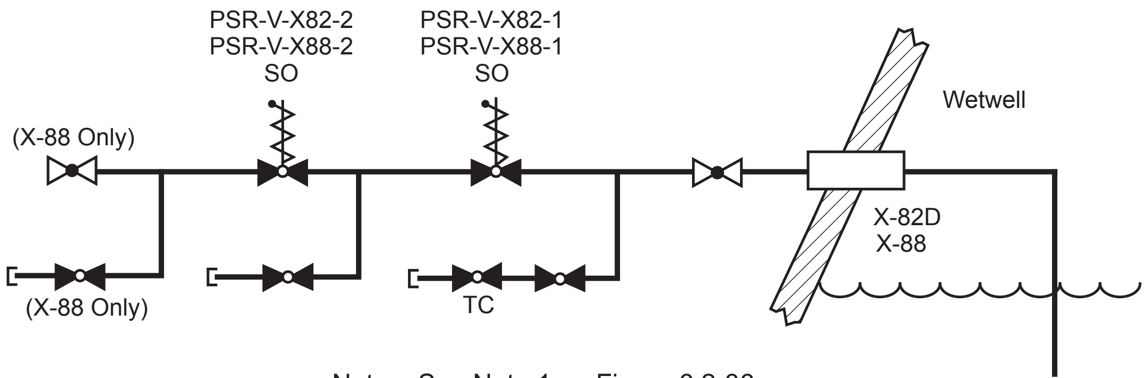
Note: See Note 1 on Figure 6.2-36

X-80B Drywell Atmosphere Sample Line
X-73F Drywell Atmosphere Sample Line

Columbia Generating Station
Final Safety Analysis Report

Isolation Valve Arrangement for Penetrations X-73F, X-77Ac, X-77Ad, X-80B

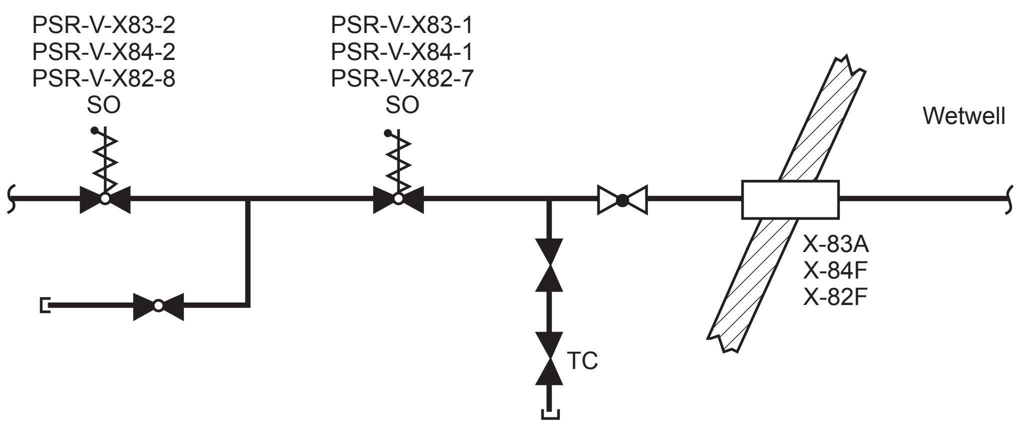
Draw. No. 920843.32 | Rev. 1 | Figure 6.2-57



Note: See Note 1 on Figure 6.2-36

<u>X-82D - Sample Return to Suppression Pool</u>

<u>X-88 - Suppression Pool Sample Line</u>



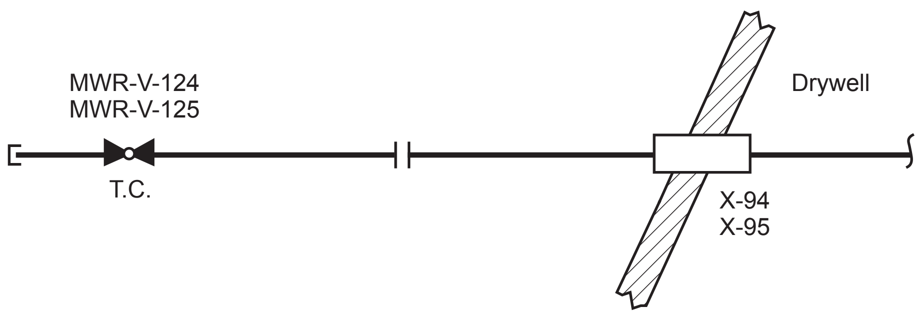
Note: See Note 1 on Figure 6.2-36

<u>X-82F- Suppression Pool Atm. Sample Return</u>

<u>X-83A- Suppression Pool Atm. Sample Line</u>

<u>X-84F- Suppression Pool Atm. Sample Line</u>

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-82D, X-82F, X-83A, X-84F, X-88		
	Draw. No. 920843.33	Rev. 1	Figure 6.2-58



X-94 - Decon Solution Supply Header
X-95 - Decon Solution Return Header

Columbia Generating Station **Final Safety Analysis Report**	**Isolation Valve Arrangement for Penetrations X-94 and X-95**	
Draw. No. 920843.34	Rev.	Figure 6.2-59

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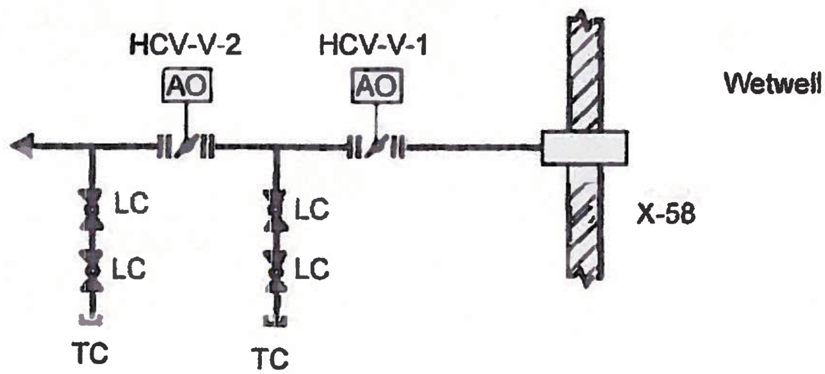

Columbia Generating Station
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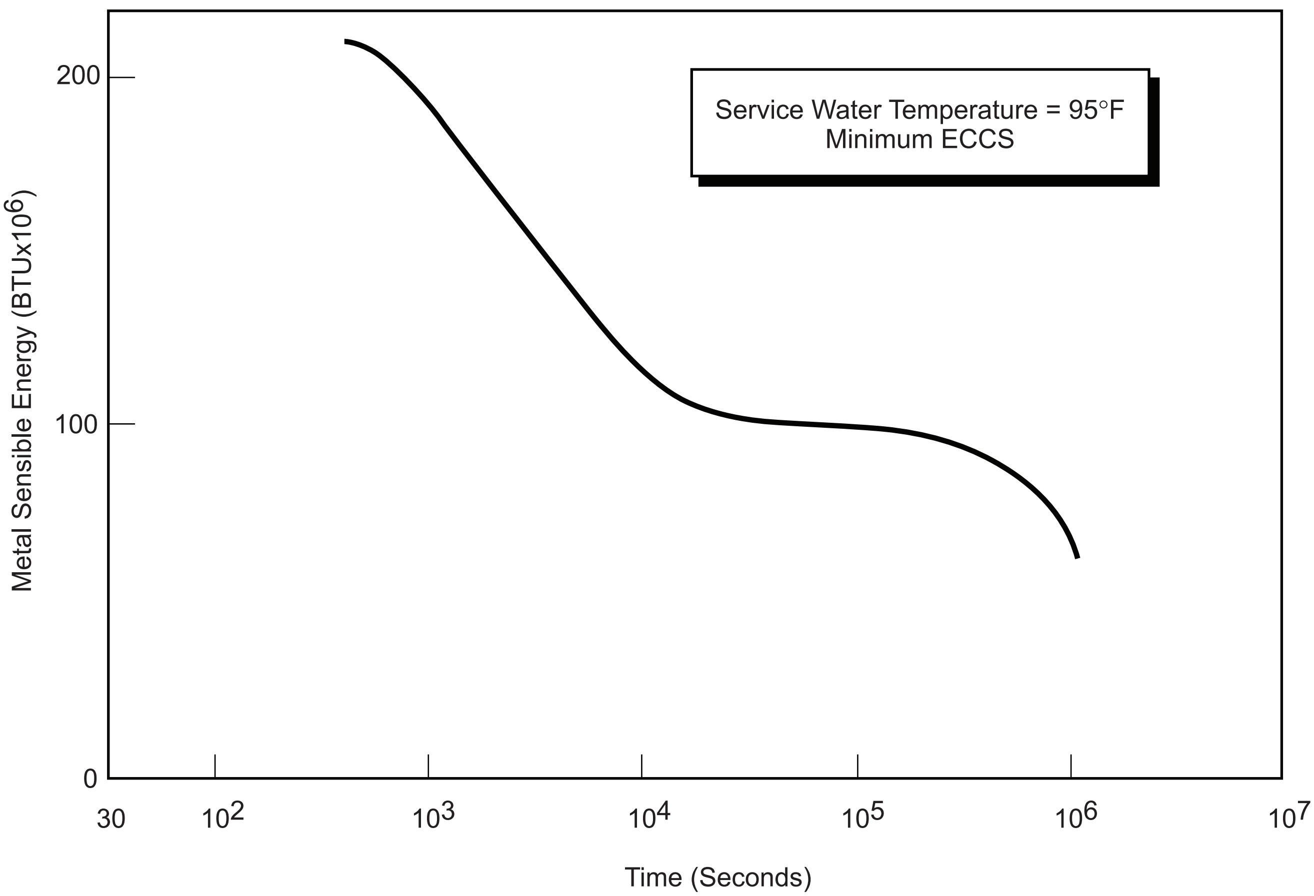
Isolation Valve Arrangement for Penetration X-58

Draw. No. 170619.1	Rev.	Figure 6.2-60A



Columbia Generating Station
Final Safety Analysis Report

Sensible Energy Transient in the Reactor Vessel and Internal Metals - Original Rated Power

Draw. No. 960222.66	Rev.	Figure 6.2-61

6.3 EMERGENCY CORE COOLING SYSTEM

This section provides the design bases for the emergency core cooling systems (ECCS), the description of the systems, the postulated ECCS response to a spectrum of accidents, and a performance evaluation. Subsection 6.3.1 discusses the design bases. Subsection 6.3.2 describes the systems. Subsection 6.3.3 discusses the system responses and the evaluation of the system performance. The ECCS design and postulated response are based on information developed by the original nuclear steam supply system (NSSS) vendor, General Electric.

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

Reload analysis performed by the fuel vendor in support of the current cycle of operation is performed in a manner that maintains the validity of the design analysis discussed in this section. The operational limits resulting from this cycle-specific analysis are reported in the cycle-specific Core Operating Limits Report (COLR).

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against postulated loss-of-coolant accidents (LOCAs) caused by ruptures in primary system piping. The functional requirements are such that the system performance under all postulated LOCA conditions satisfies the requirements of 10 CFR 50.46. The ECCS is designed to meet the following requirements:

a. Protection is provided for any primary line break up to and including the double-ended guillotine (DEG) break of the largest line,

b. Two independent and diverse cooling methods (flooding and spraying) are provided to cool the core,

c. One high-pressure cooling system is provided which is capable of maintaining water level above the top of the core and preventing automatic depressurization system (ADS) actuation for line breaks less than 1 in. nominal diameter,

d. No operator action is required until 10 minutes after an accident, and

e. A sufficient water source and the necessary piping, pumps, and other hardware are provided so that the containment and reactor core can be flooded for possible core heat removal following a LOCA.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

a. The ECCS conforms to licensing requirements and design practices of isolation, separation, and single failure considerations.

b. The ECCS network has a built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. The following equipment makes up the ECCS:

   1. High-pressure core spray (HPCS),
   2. Low-pressure core spray (LPCS),
   3. Low-pressure coolant injection (LPCI), three loops, and
   4. Automatic depressurization system (ADS).

c. The ADS is designed to remain operational following a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and wiring.

d. In the event of a break in a pipe that is not a part of the ECCS, no single active component failure in the ECCS can prevent automatic initiation and successful operation of less than the following combination of ECCS equipment:

   1. Three LPCI loops, the LPCS and the ADS (i.e., HPCS failure), or

   2. Two LPCI loops, the HPCS and the ADS (i.e., LPCS diesel generator failure), or

   3. One LPCI loop, the LPCS, the HPCS and ADS (i.e., LPCI diesel generator failure).

e. In the event of a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS can prevent automatic initiation and successful operation of less than the following combination of ECCS equipment:

   1. Two LPCI loops and the ADS, or
   2. One LPCI loop, the LPCS and the ADS, or
   3. One LPCI loop, the HPCS and the ADS, or
   4. The LPCS, the HPCS, and ADS.

These are the minimum ECCS combinations which result after assuming any single active component failure and assuming that the ECCS line break disables the affected system.

f. Long term (10 minutes after initiation signal) cooling requires the removal of decay heat by means of the standby service water system. In addition to the break which initiated the loss of coolant event, the system is able to sustain one failure, either active or passive, and still have at least one ECCS pump (LPCI, HPCS, or LPCS) operating with a residual heat removal (RHR) heat exchanger loop with 100% service water flow.

g. Offsite power is the preferred source of power for the ECCS network and every reasonable precaution is made to ensure its high availability. However, onsite emergency power is provided with sufficient diversity and capacity so that all the above requirements can be met if offsite power is not available.

h. The onsite diesel fuel reserve is designed in accordance with IEEE 308-1971 criteria.

i. Diesel-load configuration is as follows:

   1. LPCI loop A (with heat exchanger) and the LPCS connected to the Division 1 diesel generator.

   2. LPCI loop B (with heat exchanger) and loop C connected to the Division 2 diesel generator.

   3. The HPCS connected to the Division 3 diesel generator.

j. Systems which interface with but are not part of the ECCS are designed and operated such that failure(s) in the interfacing systems do not propagate to and/or affect the performance of the ECCS.

k. Non-ECCS systems interfacing with the ECCS buses are automatically shed from and/or isolated from the ECCS buses when a LOCA signal exists and offsite ac power is not available.

l. No more than one storage battery is connected to a dc power bus.

m. The logic required to automatically initiate the ECCS is capable of being tested during plant operation. Each system of the ECCS including flow rate and sensing network is capable of being tested during shutdown or during reactor operation. Pump discharge is routed to the suppression pool or condensate

storage tank through a test line. The injection line isolation valves and isolation check valves are tested in accordance with Section 3.9.6.

n. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic, and pneumatic, as applicable) are installed in such a manner that they are an integral and nonseparable part of the design.

6.3.1.1.3 Emergency Core Cooling System Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from movement, thermal stresses, the effects of the LOCA, and the safe shutdown earthquake (SSE).

The ECCS is protected against the effects of pipe whip which might result from piping failures up to and including the LOCA. This protection is provided by separation, pipe whip restraints, or energy absorbing materials. Any of these three methods is applied to provide protection against damage to ECCS piping and components which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level.

Physical separation outside the drywell is achieved as follows:

a. The ECCS is separated into three functional groups:

   1. HPCS

   2. LPCS and LPCI loop A with 100% service water and one RHR heat exchanger

   3. LPCI loops B and C with 100% service water and one RHR heat exchanger

b. The equipment in each group is separated from that in the other two groups. In addition, HPCS and the reactor core isolation cooling (RCIC) (which is not an ECCS) are separated.

c. Separation barriers exist between the functional groups and between HPCS and RCIC as required to ensure that environmental disturbances affecting one functional group will not affect the remaining groups.

6.3.1.1.4 Emergency Core Cooling System Environmental Design Basis

The only active components in the HPCS, LPCS, or LPCI systems located in the drywell are the check valves. These safety-related, injection/isolation check valves are qualified for the

accident environmental requirements specified in Section 3.11 and are installed above the expected flood level in the drywell. The ADS valves are located in the drywell and are qualified to the accident environmental conditions specified in Section 3.11.

The balance of the ECCS equipment (e.g., pumps, motors) is qualified for accident environmental requirements specified in Section 3.11.

Note: "Qualification" of safety-related mechanical (SRM) equipment is not part of the Columbia Generating (CGS) Station Environmental Qualification (EQ) 10 CFR 50.49 program but is part of the process that maintains the plant design basis.

6.3.1.2 Summary Descriptions of Emergency Core Cooling System

The ECCS injection network consists of an HPCS system, an LPCS system, and the LPCI mode of the RHR system. The ADS assists the injection network under certain conditions. These systems are briefly described in this section as an introduction to more detailed system descriptions in Section 6.3.2.

6.3.1.2.1 High-Pressure Core Spray

The HPCS pumps water through a peripheral ring spray sparger mounted above the reactor core. Coolant is supplied over the entire range of system operation pressures. The primary purpose of HPCS is to maintain reactor vessel inventory after small breaks which do not depressurize the reactor vessel. The HPCS also provides spray cooling heat transfer during breaks which uncover the core. The standby liquid control (SLC) system also injects to the reactor pressure vessel (RPV) by means of the HPCS core spray header. An SLC injection will occur with HPCS flow either on or off.

6.3.1.2.2 Low-Pressure Core Spray

The LPCS is an independent loop similar to the HPCS, the primary difference being the LPCS delivers water over the core at low reactor pressures. The primary purpose of the LPCS is to provide inventory makeup and spray cooling during large breaks which uncover the core. When assisted by the ADS, LPCS also provides protection for small breaks.

6.3.1.2.3 Low-Pressure Coolant Injection

The LPCI is an operating mode of the RHR system. Three pumps deliver water from the suppression pool to the bypass region inside the shroud through three separate reactor vessel penetrations to provide inventory makeup following large pipe breaks. When assisted by the ADS, LPCI also provides protection for small breaks.

6.3.1.2.4 Automatic Depressurization System

The ADS utilizes seven of the reactor safety/relief valves (SRVs) to reduce reactor pressure during small breaks in the event of HPCS failure. When the vessel pressure is reduced to within the capacity of the low pressure systems (LPCS and LPCI), the systems provide inventory makeup so that acceptable postaccident temperatures are maintained in the core.

6.3.2 SYSTEM DESIGN

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The process and flow diagrams for the ECCS are specified in the various Sections of 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The starting signal for the ECCS comes from at least two independent and redundant sensors of drywell pressure and low reactor water level, except ADS which requires low reactor water level and indication that LPCI or LPCS is available. The ECCS is actuated automatically and requires no operator action during the first 10 minutes following the accident.

The preferred source of power for all three ECCS divisions is from regular ac power to the plant. Regular ac power is from the main transformers [TR-N(1) and (2)] during plant operation or from the startup transformer (TR-S) (an offsite power source) when the main generator is off-line. Should regular ac power be lost, Division 1 (LPCS and LPCI loop A) and Division 2 (LPCI loops B and C) would be transferred to a second offsite power supply and backup transformer (TR-B). Division 3 (HPCS) would be powered from its onsite standby diesel. If the backup transformer were also lost, Divisions 1 and 2 would then be powered from their respective and independent onsite standby diesels. A more detailed description of the power supplies for the ECCS is contained in Section 8.3.

6.3.2.2.1 High-Pressure Core Spray System

Process and flow diagrams are shown in Figures 6.3-3 and 6.3-4. The HPCS system consists of a single motor-driven centrifugal pump, a spray sparger in the reactor vessel located above the core (separate from the LPCS sparger), and associated system piping, valves, controls, and instrumentation. The system is designed to operate from regular ac or from a standby diesel generator supply if offsite power is not available. The system is designed to the requirements of ASME Section III.

With the exception of the check valve on the discharge line, all active HPCS equipment is located outside the primary containment. Suction piping is provided from the condensate storage tanks and the suppression pool. This arrangement provides HPCS the capability to use high quality water from the condensate storage tanks. In the event that the condensate storage

water supply becomes exhausted or is not available, automatic switchover to the suppression pool water source will ensure a closed cooling water supply for continuous operation of the HPCS system. The HPCS pump suction is also automatically transferred to the suppression pool if the suppression pool water level exceeds a prescribed value. The condensate storage tanks contain a reserve of approximately 135,000 gal of water just for use by HPCS and RCIC.

Remote controls for operating the motor-operated components and diesel generator are provided in the main control room. The HPCS controls and instrumentation are described in Section 7.3.1.

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level. For large breaks the HPCS system cools the core by a spray. The HPCS also provides for core cooling in the event of a station blackout. If a LOCA should occur, a low water level signal or a high drywell pressure signal initiates the HPCS and its support equipment. The system can also be manually placed in operation.

The HPCS injection automatically stops with a high water level in the reactor vessel by signaling the injection valve to close and it automatically starts again when a low water level signals the injection valve to open. The HPCS system also serves as a back-up to the RCIC system in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

The HPCS system head flow characteristic used for LOCA analyses is shown in Figure 6.3-5. When the system is started, initial flow rate is established by primary system pressure. As vessel pressure decreases, flow will increase.

When vessel pressure reaches 200 psid* the system reaches rated core spray flow. The HPCS motor size is based on peak horsepower requirements.

The elevation of the HPCS pump is sufficiently below the water level of both the condensate storage tanks and the suppression pool to provide a flooded pump suction and to meet pump net positive suction head (NPSH) requirements with the containment at atmospheric pressure and the suction strainer bed entrained with debris washed into the wetwell following a LOCA. The available NPSH at the pump suction is sufficient to meet the NPSH required (see Section 6.3.2.2.6). The available NPSH also ensures that no cavitation occurs anywhere in the pump suction line between the wetwell strainers and the pump suction.

A motor-operated valve is provided in the suction line from the suppression pool. The valve is located as close to the suppression pool penetration as practical. This valve is used to isolate the suppression pool water source when HPCS system suction is from the condensate storage

* psid - differential pressure between the reactor vessel and the suction source.

system and to isolate the system from the suppression pool in the event of a leak in the HPCS system.

A check valve, flow element, and restricting orifice are provided in the HPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system. The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room. The restricting orifice was sized during the system preoperational test to limit system flow to prescribed values.

A low flow bypass line with a motor-operated gate valve connects to the HPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage from overheating when other discharge line valves are closed. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

To ensure continuous core cooling, primary containment isolation does not interfere with HPCS operation.

The HPCS system incorporates relief valves to protect the components and piping from inadvertent overpressure. One relief valve with required capacity is located on the discharge side of the pump downstream of the check valve to relieve thermally-expanded fluid or leakage. A second relief valve is located on the suction side of the pump. The HPCS components and piping are positioned to avoid damage from the physical effects of design basis accidents such as pipe whip, missiles, high temperature, pressure, and humidity. The HPCS equipment and support structures are designed in accordance with Seismic Category I criteria. The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCS system which will permit the HPCS system to be tested. These provisions are

a. Active HPCS components are testable during normal plant operation and/or during shutdown,

b. A full flow test line is provided to route water from and to the condensate storage tanks without entering the RPV,

c. A full flow test line is provided to route water from and to the suppression pool without entering the RPV,

d. Instrumentation is provided to indicate system performance during normal and test conditions,

e. Check valves and motor-operated valves are capable of operation for test purposes, and

f. System relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.2 Automatic Depressurization System

If the HPCS cannot maintain reactor water level, the ADS, which is independent of any other ECCS, reduces the reactor pressure so that flow from LPCI and LPCS systems can enter the reactor vessel for core cooling.

The ADS employs seven of the nuclear system pressure relief valves to relieve high pressure steam to the suppression pool. The design, location, description, operational characteristics, and evaluation of the pressure relief valves are discussed in detail in Section 5.2.2. The operation of the ADS is discussed in Section 7.3.1.

6.3.2.2.3 Low-Pressure Core Spray System

Process and flow diagrams are shown in Figures 6.3-4 and 6.3-6. The LPCS system consists of a single motor-driven centrifugal pump, a spray sparger in the reactor vessel above the core (separate from the HPCS sparger), piping and valves to convey water from the suppression pool to the sparger, and associated controls and instrumentation. Design pressure and temperature of system components are based on ASME Section III.

The LPCS is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCS operates in conjunction with the ADS, the effective core cooling capability of the LPCS is extended to all break sizes because the ADS can rapidly reduce the reactor vessel pressure to the LPCS operating range. The system head flow characteristic assumed for LOCA analyses is shown in Figure 6.3-1.

The LPCS pump and all motor-operated valves can be operated individually in the control room. Operating flow and valve position indication is provided in the control room.

To ensure continuity of core cooling, primary containment isolation signals do not interfere with LPCS operation.

The LPCS discharge line to the reactor is provided with two isolation valves. One of these valves is a check valve located inside the drywell as close as practical to the reactor vessel. The LPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is

required for valve actuation during LOCA). If the LPCS line should break outside the containment, the check valve in the line inside the drywell will prevent loss of reactor water outside the containment.

The other isolation valve (which is also referred to as the LPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to LPCS discharge line penetration into the containment. The valve is capable of opening against a differential pressure equal to normal reactor pressure, minus the minimum LPCS system shutoff pressure. A permissive switch prevents the valve operator from being energized to open until the reactor vessel pressure is less than the value in Table 6.3-1. This valve is normally closed to back up the inside check valve for containment integrity purposes. A test line is provided between the two valves. The test connection line has two normally closed valves to ensure containment integrity.

The LPCS system components and piping are arranged to avoid damage from the physical effect of design-basis accidents, such as pipe whip, missiles, high temperature, pressure, and humidity.

With the exception of the check valve on the discharge line, all active LPCS equipment is located outside the primary containment.

A check valve, flow element, and restricting orifice are provided in the LPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system. The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low flow bypass globe valve. The measured flow is indicated in the main control room. The restricting orifice was sized during the system preoperational test to limit system flow to prescribed values.

A low flow bypass line with a motor-operated globe valve connects to the LPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed or reactor pressure is greater than the LPCS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

The LPCS flow passes through a motor-operated pump suction valve that is normally open. This valve can be closed from the control room to isolate the LPCS system from the suppression pool should a leak develop in the system. This valve is located as close to the suppression pool penetration as practical. Since the LPCS takes a suction on the suppression pool, a closed loop is established for the water escaping from the break.

The LPCS pump is located in the reactor building sufficiently below the water level in the suppression pool to ensure a flooded pump suction and to meet pump NPSH requirements with the containment at atmospheric pressure and postaccident debris entrained on the beds of the suction strainers. A pressure gauge is provided to indicate the suction head. The available NPSH at the pump suction is sufficient to meet the NPSH required (see Section 6.3.2.2.6). The LPCS system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions. One relief valve is located on the pump discharge. A second relief valve is located on the suction side of the pump.

The LPCS system piping and support structures are designed in accordance with Seismic Category I criteria. The system is assumed to be filled with water for seismic analysis. Provisions are included in the LPCS system which will permit the system to be tested. These provisions are

a. All active LPCS components are testable during normal plant operation and/or shutdown,

b. A full flow test line is provided to route water from and to the suppression pool without entering the RPV,

c. A suction test line supplying high quality water is provided to test pump discharge into the RPV during normal plant shutdown,

d. Instrumentation is provided to indicate system performance during normal and test operations,

e. Check valves and motor-operated valves are capable of operation for test purposes, and

f. Relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.4 Low-Pressure Coolant Injection System

The LPCI system is an operating mode of the RHR system. The LPCI system is automatically actuated by low water level in the reactor and/or high pressure in the drywell and, when reactor vessel pressure is low enough, uses the three RHR motor-driven pumps to draw suction from the suppression pool and inject cooling water flow into the reactor core to cool the core by flooding. Each loop has its own suction and discharge piping and separate vessel nozzle which connects with the core shroud to deliver flooding water on top of the core. The system is a high volume core flooding system. The design pressure and temperature of system components is based on ASME Section III.

The LPCI system, like the LPCS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI operates in conjunction with the ADS, then the effective core cooling capability of the LPCI is extended to all break sizes because the ADS will rapidly reduce the reactor vessel pressure to the LPCI operating range. The head flow characteristic assumed in the LOCA analyses for the LPCI system is shown in Figure 6.3-2.

The process and flow diagram for the RHR system is contained in Section 5.4.7.

The pumps, piping, controls, and instrumentation of the LPCI loops are separated and protected so that no single physical event, including missiles, can make all loops inoperable.

To ensure continuity of core cooling, primary containment isolation signals do not interfere with the LPCI mode of operation.

Each LPCI discharge line to the reactor is provided with two isolation valves. The valve inside the drywell is a check valve and the valve outside the drywell is a motor-operated gate valve. No power is required to operate the check valve inside of the drywell since it opens with LPCI injection flow. If a break were to occur outboard of the check valve, the valve would shut isolating the reactor from the line break.

The motor-operated isolation valve outside of the drywell is also the LPCI injection valve and it is located as close as practical to the drywell wall. It is capable of opening against a differential pressure equal to normal reactor pressure minus the upstream pressure with the RHR pump running at minimum flow. A permissive switch prevents the valve operator from energizing open until the reactor vessel pressure is as shown in Table 6.3-1.

Figure 5.4-16 process diagram shows the additional flow paths available other than the LPCI mode. However, the low water level or high drywell pressure signals which automatically initiate the LPCI mode are also used to isolate all other modes of operation and revert system valves to the LPCI lineup. Inlet and outlet valves from the heat exchangers however receive no automatic signals. The heat exchanger inlet valves are key-locked open and the outlet valves are administratively controlled in the open position. The RHR system continues in the LPCI mode until the operator determines that another mode of operation is needed (such as containment cooling) and takes action to manually initiate that mode. The LPCI will not be diverted to any other mode of operation until adequate core cooling is ensured. No operator actions are needed during the short term.

A check valve in the pump discharge line is used together with a discharge line fill system to keep the discharge lines full of water, thereby, preventing water hammer on pump start. A flow element in each pump discharge line is used to provide a measure of system flow and to originate automatic signals for control of the pump minimum flow valves. The minimum flow

valve permits a small flow to the suppression pool in the event no discharge valve is open or in the case of a LOCA where vessel pressure is higher than pump shutoff head.

Using the suppression pool as the source of water, the LPCI pump establishes a closed loop for recirculation of LPCI water escaping from the break.

The design pressures and temperatures, at various points in the system, during each of the several modes of operation of the RHR system can be obtained from the RHR process diagram in Figures 5.4-16 and 5.4-17.

The LPCI pumps and equipment are described in detail in Section 5.4.7. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in Section 6.2.2. The portions of the RHR required for accident protection including support structures are designed in accordance with Seismic Category I criteria. The available NPSH at the pump suction is sufficient to meet the NPSH required (see Section 6.3.2.2.6). The characteristics for the RHR (LPCI) pumps are shown in Figures 5.4-18, 5.4-19, and 5.4-20.

The LPCI system incorporates a relief valve on each of the pump discharge lines which protects the components and piping from overpressure conditions.

There is a relief valve on the common suction header from the reactor recirculation piping for loops A and B. In addition, each of the three suction pipes from the suppression pool for loops A, B, and C is provided with a relief valve.

The following provisions are included in the LPCI system to permit testing of the system:

a. Active LPCI components are designed to be testable during normal plant operation and/or during plant shutdown,

b. A discharge test line is provided for the three pumps to route suppression pool water back to the suppression pool without entering the RPV,

c. A suction test line, supplying high quality water, is provided to test discharge into the RPV during normal plant shutdown,

d. Instrumentation is provided to indicate system performance during normal and test operations,

e. Check valves and motor-operated valves are capable of operation for test purposes,

f. Lines taking suction from the recirculation system are provided for loops A and B to provide for shutdown cooling and to test pump discharge into the RPV during plant shutdown, and

g. System relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.5 Emergency Core Cooling System Discharge Line Fill System

The ECCS discharge line fill system is designed to maintain the pump discharge lines in a filled condition to ensure the time between the signal to start the pump and the initiation of flow into the RPV is minimized.

Since the ECCS discharge lines are elevated above the suppression pool, check valves are provided near the pumps to prevent back flow from emptying the lines into the suppression pool. To ensure that any leakage from the discharge lines is replaced and the lines are always kept full, a water leg pump system is provided for each of the three ECCS divisions. The power supply to these pumps is classified as essential when the main ECCS pumps are not operating. Indication is provided in the control room as to whether the water leg pumps are operating.

6.3.2.2.6 Emergency Core Cooling System Suction Strainers

NRC Bulletin 96-03, Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors, requested that the ECCS suction strainers be evaluated with regard to the potential for plugging during accident conditions. The ECCS suction strainers were replaced to conform with the requirements of the bulletin.

There are two suction strainers for each ECCS pump. Each strainer is Quality Class I, Seismic Category I, Cleanliness Class B, and has a service rating of ANSI 150#. Strainer materials and fabrication meet ASME Section III, Class 2 requirements. The “N” stamp is not applied since the strainers cannot be hydrostatically tested. The strainer body is stainless steel 304 or 316, or engineer approved equal, suitable for submergence in high quality water during a 40-year lifetime.

The ECCS suction strainers have a cylindrical stacked disk configuration, as shown on Figures 6.3-7 and 6.3-8. The strainers are attached to ANSI 150# RF flanges. The following information identifies the overall dimensions, rated flow conditions, and other considerations used in the design of the ECCS strainers.

Strainer sizes were selected based on several criteria. The strainer beds had to be big enough to entrain post-LOCA wetwell debris without exceeding the maximum allowable head losses. The maximum head losses across the strainers were determined based on maintaining sufficient pressure in the pump suction lines to preclude cavitation under run-out conditions with the

suppression pool water at 204.5°F. The strainer sizes were also limited by physical constraints in the suppression pool and hydrodynamic design considerations.

The screen size for the suction strainers on the RHR system is based on the more restrictive criteria set by the pump manufacturer or the spray nozzle orifice opening. The pump manufacturer imposed a maximum particle size of 0.09375 in., based on the size of the smallest orifice/flow path in the pump mechanical seal. This is significantly more restrictive than the requirement imposed by the spray nozzles which have an orifice opening of 0.26563 in. Accordingly, the strainers were specified to prevent the passage of particles 0.09375 in. or greater. The diameter of the holes in the strainer perforated plate is 0.09375 in. Particles smaller than 0.09375 in. (3/32 in.) would normally pass through the ECCS strainers. However, following a LOCA, fibrous debris is postulated to be in the wetwell. This debris, once deposited on the strainers, would cause particles finer than 3/32 in. to be entrained on the strainer bed.

Hydrodynamic and pressure loads were developed which were applied concurrently with the load due to process flow through the strainer. The hydrodynamic pressure loads on the strainer address actual strainer geometries and the drag effects resulting from the strainers, dimensional, and porous properties.

The following information provides details regarding location, size, and submergence of each ECCS strainer, relative to the minimum suppression pool water level of 466 ft 0.75 in. The location of the RHR strainers is also shown in Figure 6.2-32.

ECCS Pump	Quantity	Centerline Elevation	Approximate Azimuth	Minimum Submergence (ft)	Outer Diameter (in.)	Length (in.)
RHR-P-2A	2	447 ft	26°	17.1	47.5	28
RHR-P-2B	2	447 ft	153°	17.1	47.5	28
RHR-P-2C	1	447 ft 7 in.	38°	17.0	36	42
RHR-P-2C	1	447 ft 7 in.	38°	17.0	36	70
LPCS-P-1	1	447 ft 7 in.	58°	17.0	36	36
LPCS-P-1	1	447 ft 7 in.	38°	17.0	36	76
HPCS-P-1	2	438 ft 9 in.	90°	25.8	36	51

During normal operation, corrosion products accumulate in the suppression pool forming a sediment on the pool surfaces. Following a LOCA, those sediments are assumed to be resuspended in the suppression pool water and entrained on the strainer beds, together with other debris.

A spectrum of breaks were analyzed to determine the maximum amount of debris which could be in the wetwell following a LOCA. The ECCS strainers have been designed to provide a satisfactory head loss after entraining all wetwell debris following a LOCA. The analysis was

performed using the guidance provided in Reference 6.3-3 and determined the maximum postulated quantities of debris that would be in the suppression pool following a LOCA. The debris types that are assessed in the analysis include the following:

Fiber	TempMat Fiber Insulation, miscellaneous fiber sources (i.e., cloth, rope)
RMI	Reflective Metal Insulation foils, equipment tags (modeled as RMI)
Sediment	Suppression pool sediment, dirt, dust, and concrete dust
Coatings	Qualified epoxy coating within the break zone of influence
Coatings	Unqualified (latent) paint in drywell
Coatings	Zinc unqualified coating in wetwell
Labels	Adhesive backed labels
Rust	Rust flakes from uncoated surfaces in drywell and wetwell

A portion of the strainer surface area was reserved (presumed unavailable in the analysis) to provide for additional design margin.

The debris that is postulated to reach the suppression pool is assumed to be fully entrained on the strainers of ECCS pumps that are available to operate, in proportion to their relative flow rates.

Calculations demonstrating the acceptability of the new strainers and the NPSH for all ECCS pumps were performed in accordance with Regulatory Guide 1.1.

NPSH = Wetwell air space pressure + static pressure - friction losses - vapor pressure

The NPSH calculations are based on a peak suppression pool temperature of 204.5°F and bounding flowrates for the time of peak pool temperature. This is the bounding configuration for minimizing available NPSH. The analysis which established the 204.5°F temperature used the following conservative assumptions:

a. The suppression pool is the only heat sink available to the containment system. No credit is taken for passive structural heat sinks in the drywell, suppression chamber air space, or in the suppression pool;

b. No cooling is assumed for 10 minutes. After 10 minutes, the RHR heat exchangers are assumed to remove energy by recirculating water from the suppression pool through the RHR heat exchangers; and

c. The suppression pool volume is at minimum Technical Specifications level (112,197 ft^3), with an initial condition of 90°F. Standby service water, which cools the RHR heat exchanger, is also at 90°F.

In addition, the NPSH calculation used the following conservative assumptions:

a. The suppression chamber is assumed to be at 14.7 psia throughout the event,

b. No credit is taken for expansion of the suppression pool volume from its initial volume at 90°F to 204.5°F, and

c. The NPSH required is the pump manufacturer's NPSH required plus two feet.

Vapor pressure at the peak suppression pool temperature of 204.5°F is 12.6 psia (30.3 ft). In accordance with Regulatory Guide 1.1, "no increase in containment pressure from that present prior to postulated loss-of-coolant accidents" is assumed. Therefore, the wetwell air space pressure is assumed to be 0 psig. Based on a minimum suppression pool level of 466 ft 0.75 in., summary NPSH data for each of the ECCS systems is provided below:

Summary of ECCS Pumps NPSH	RHR	LPCS	HPCS
NPSH available at pump suction (ft)	32.2	37.7	40.7
NPSH required (ft)	16	15	26
NPSH margin at pump suction (ft)	16.2	22.7	14.7

The ECCS strainers were designed to ensure that with the strainers entrained with debris there was sufficient pressure in the suction line to preclude cavitation at the high points of the suction lines.

The strainer designs are based upon the suppression pool temperature and pressure of 204.5°F and 14.7 psia, respectively. The actual suppression pool atmosphere is calculated to be higher than 14.7 psia following a LOCA, adding pressure to the suction lines, and increasing the margin to cavitation at the lines' high points.

With no operator action, the RHR valve alignment will result in approximately 40% of its LPCI flow through the RHR heat exchangers, with the balance of the flow through the open heat exchanger bypass valve. For a design basis recirculation line break, the partial flow through the heat exchangers will remove heat at about 75% of their design heat rate. At 10 minutes, the operator must close the bypass valve to achieve full cooling.

There are sufficient margins in the NPSH and suppression pool analyses to ensure that the lack of operator action for 20 minutes will not challenge the required NPSH for the ECCS pumps at the pump nozzles or allow cavitation anywhere in the suction lines.

All ECCS suction lines in the suppression pool have been designed with large diameter piping (24 in.) to reduce the inlet velocity (maximum 6.67 ft/sec). This inlet velocity will support a vortex of no more than 2.5 ft in height. The inlet to each of the ECCS suction lines is at least 17 ft below the minimum suppression pool level. Vortex formation at the ECCS pump inlets as a result of lowered suppression pool level is thus not considered a problem.

Since it has been conservatively established that all ECCS suction lines are adequately submerged to preclude formation of an undesirable vortex, no confirmatory preoperational testing is required.

6.3.2.3 Applicable Codes and Classifications

The applicable codes and classification of the ECCS are specified in Section 3.2. All vital piping systems and components (pumps, valves, etc.) for the ECCS comply with ASME Section III of the Edition and Addenda that were mandatory at the time of their order or a later Edition and Addenda. The piping and components of the ECCS which form part of the reactor coolant pressure boundary are Safety Class 1. The remaining piping and components are Safety Class 2, 3, or G, as indicated in Section 3.2. The equipment and piping of the ECCS are designed to the requirements of Seismic Category I. This seismic designation applies to all structures and equipment essential to the core cooling function. The IEEE codes applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Section 6.1. Nonmetallic materials such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials, etc., are selected as a result of engineering evaluation for compatibility with other materials in the system and the surroundings pertaining to chemical, radiolytic, mechanical, and nuclear effects. Materials used were reviewed and evaluated and found to be acceptable with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A single failure analysis shows that no single failure prevents the starting of the ECCS or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single failure proof, with the exception of the LPCI and ADS. Therefore, it is expected that single failures will disable individual systems of the ECCS. The consequences (remaining available systems) of the most severe single failures are shown in Table 6.3-3. The LOCA caused by a pipe

break in an ECCS, with the single failure of a DG in another division and the loss of offsite power, will result in the minimum available ECCS.

During a LOCA, for protection against and mitigation of a single passive ECCS failure (pump seal or valve bonnet leak), a Class 1E level instrument is mounted just above floor level in each ECCS pump room and in the RCIC pump room to detect such failures (after 24 hours) during long-term cooling (assuming loss of the other non-Class 1E leak detection equipment). The maximum leak rate postulated is 23 gpm, which results from the total failure of an RHR pump seal. Operator action will isolate the source of the leak after detection and before it has any adverse effects on ECCS operation.

The functional testing and calibration of the ECCS is prescribed by the Technical Specifications.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal stresses, loadings from a LOCA, and seismic effects.

The ECCS piping and components located inside the ECCS and RCIC/CRD pump rooms are protected from flooding and missiles generated outside the room in which the particular pump is located by the reinforced-concrete structure, including doors and wall penetrations, which minimize the effects of missiles and flooding. Each pump room contains the majority of the active components of one emergency core cooling or RCIC/CRD subsystem.

The ECCS is protected against the effects of pipe whip which might result from piping failures up to and including the design basis LOCA. This protection is provided by separation, pipe whip restraints, and energy absorbing materials. These three methods are applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness.

The component supports which protect against damage from movement and from seismic events are discussed in Section 5.4.14. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in Section 3.9.3.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in Section 6.3.2.2 as part of the individual system descriptions and in Section 6.3.1.1.2 as part of the overall system description.

6.3.2.8 Manual Actions

The ECCS is actuated automatically and requires no operator action during the first 10 minutes following an accident. During the long-term cooling period (after 10 minutes), the operator will initiate the RHR system heat exchangers in the suppression pool cooling mode.

6.3.3 EMERGENCY CORE COOLING SYSTEM PERFORMANCE EVALUATION

The ECCS performance is evaluated using analytical methods in compliance with the requirements of 10 CFR 50 Appendix K to show conformance to the acceptance criteria of 10 CFR 50.46. The methods used analyze the full LOCA break spectrum, including small, intermediate, and large size breaks. A spectrum of breaks and single failures is run using a consistent set of initial conditions to determine the resultant peak clad temperature (PCT). The PCT is calculated for the potentially limiting events and the design basis break is identified based on that parameter. The break spectrum analysis results confirm that considerable margin exists to the acceptance criteria of 10 CFR 50.46. The break spectrum analysis addresses two loop and single loop operation. The following Chapter 15 accidents require ECCS operation:

a. Steam system piping break - outside containment, Section 15.6.4,
b. Loss-of-coolant accidents - inside containment, Section 15.6.5, and
c. Feedwater line break - outside containment, Section 15.6.6.

The baseline analyses to verify the adequacy of ECCS design were performed by the NSSS vendor for the initial core, a GE 8 x 8 fueled core. The adequacy of the ECCS design was verified subsequently for Single Loop Operation (SLO), Maximum Extended Load Line Limit Analysis (MELLLA), reactor power uprate, changes in fuel design, and adjustable speed drive reactor recirculation pumps.

The NSSS vendor analysis established the large break in the reactor recirculation suction line, with failure of the HPCS diesel generator as the limiting design basis accident (DBA) event. The NSSS vendor analyses are described in References 6.3-1, 6.3-2, 6.3-4, 6.3-5, and 6.3-7.

The GE14 analysis establishes the small break of 0.07 ft^2 in the recirculation suction line with top peaked axial power shape and failure of the HPCS diesel generator as the limiting break event. The GE14 analysis is described in References 6.3-15 and 6.3-5.

The GNF2 analysis confirms the small break of 0.07 ft^2 in the recirculation suction line as still limiting, with top peaked axial power shape and failure of the HPCS diesel generator assumed. The GNF2 analysis is described in Reference 6.3-16.

A summary description of the reload design basis LOCA analysis methods is provided in this section.

6.3.3.1 Emergency Core Cooling System Bases for Technical Specifications

The MAPLHGRs calculated in this performance evaluation provide a basis to ensure conformance with the acceptance criteria of 10 CFR 50.46. The MAPLHGR limits are determined from ECCS limits (PCT) only, because the thermal-mechanical limits are incorporated into the LHGR limits. The MAPLHGR limits are provided in the COLR. Testing requirements for ECCS are discussed in Section 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

6.3.3.2 Acceptance Criteria for Emergency Core Cooling System Performance

The applicable acceptance criteria, extracted from 10 CFR 50.46, are listed and a discussion of conformance is provided.

Criterion 1, Peak Cladding Temperature
"The calculated maximum fuel element cladding temperature shall not exceed 2200° F."

Criterion 2, Maximum Cladding Oxidation
"The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation."

Criterion 3, Maximum Hydrogen Generation
"The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react."

- Compliance with Criteria 1, 2, and 3 is summarized in Table 6.3-5 and Figure 6.3-9.

Criterion 4, Coolable Geometry
"Calculated changes in core geometry shall be such that the core remains amenable to cooling."

- Conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2.

Criterion 5, Long-Term Cooling
"After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core."

- Compliance with this criterion was demonstrated during the original and uprate review of the plant ECCS design (Reference 6.3-1 and 6.3-7). Compliance was also demonstrated for GE14 and GNF2 fuel (Reference 6.3-6) Briefly summarized, the core remains covered to at least the jet pump suction elevation and spray cooling cools the uncovered region. Without core spray, two LPCI pumps alone submerge the core to an equilibrium level above the jet pump suction elevation and prevent substantial heatup and peak cladding temperature.

6.3.3.3 Single Failure Considerations

The consequences of potential operator errors and single failures and potential for submergence of valve motors in the ECCS are discussed in Section 6.3.2. The following bounding single failures are described in Table 6.3-3:

a. Low-pressure coolant injection emergency diesel generator, which powers two LPCI pumps,

b. Low-pressure core spray emergency diesel generator, which powers one LPCI pump and one LPCS pump, and

c. High-pressure core spray.

The systems that remain operational after these failures are shown in Table 6.3-3. For large breaks, failure of one of the diesel generators is, in general, the more severe failure. Substantial amounts of initial vessel inventory are lost through the break during the blowdown. With fewer systems available, there is less ECCS flow available for reflooding the core and the core will reflood later. The later reflooding results in higher peak cladding temperatures. For small breaks LOCAs, a HPCS failure is the worst single failure.

As shown in Table 6.3-3, at least one core spray system remains operational, if the break is not in the ECCS piping. Long term core cooling is also assured without core spray (Reference 6.3-6). Two LPCI pumps alone submerge the core to an equilibrium level above the jet pump suction elevation and prevent substantial heatup and peak cladding temperature increase.

If the break occurred in the HPCS or LPCS and the single failure were the other spray system, no core spray system would be available to provide long term cooling. Because the remaining core cooling systems would be able to maintain the water level above the top of the fuel, adequate core cooling is provided without a spray system.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident is as follows:

a. Receiving an initiation signal,
b. A small lag time (to open all valves and have pumps to rated speed), and

c. ECCS flow entering the vessel.

Key operating parameters, fuel parameters and ECCS initiation parameters used in the LOCA analysis are provided in Tables 6.3-2a, 6.3-2b and 6.3-2c, respectively. The representative sequences of events are presented in Tables 6.3-4a and 6.3-4b. System flow curves are provided in Figures 6.3-1 and 6.3-2.

Operator action is not required during the short-term cooling period following the LOCA. During the long-term cooling period (after 10 minutes), the operator may take actions to:

a. Use ECCS for vessel level control,

b. Use ADS or SRVs for vessel pressure control, or

c. Place systems into operation, such as containment cooling, standby liquid control, or drywell spray.

6.3.3.5 Use of Dual Function Components for Emergency Core Cooling System

With the exception of the LPCI system, the systems of the ECCS are designed only to cool the reactor core following a loss of reactor coolant. To this extent, components or portions of these systems (except for pressure relief) are not required for operation of other systems that have emergency core cooling functions, or vice versa. Because the ADS initiating signal or the overpressure signal opens the SRVs there is no conflict between the two SRV functions.

The LPCI subsystem uses the RHR pumps and some of the RHR valves and piping. When reactor water level is low or a high drywell pressure exists, the LPCI subsystem has priority through the valve control logic over the other RHR subsystems for containment cooling or shutdown cooling. Immediately following a LOCA, the RHR system is aligned to the LPCI mode.

The primary storage facility for ECCS water is the suppression pool which is not shared with any other systems except as a secondary source for RCIC. The RCIC system, although not an ECCS, may supply water to the reactor during LOCA conditions while reactor pressure is above the minimum credited pressure. Since any leakage from the core and safety/relief discharge drains back to the suppression pool, sufficient quantity of water is available for core cooling (see Table 6.2-4).

The condensate storage tanks comprise the normal water source for HPCS and RCIC. A minimum of 135,000 gal is required exclusively for RPV makeup. The HPCS and RCIC systems will automatically switch suction to the suppression pool when the minimum condensate storage tank supply is exhausted. The HPCS system will also automatically switch suction to the suppression pool when suppression pool level reaches a predetermined high level limit.

6.3.3.6 Emergency Core Cooling System Analyses for Loss-of-Coolant Accident

A LOCA may occur over a wide spectrum of break locations and sizes. Responses to the break vary significantly over the break spectrum. The largest possible break is a DEG; however, this is not necessarily the most severe challenge to the ECCS. Because of these complexities, an analysis covering the full range of break sizes and locations is required. The LOCA analysis also assumes a coincident loss of power and an additional single failure. See References 6.3-7 and 6.3-14 for more detail.

Regardless of the initiating break characteristics, the event response is separated into three phases; blow down, refill and reflood. The relative duration of each phase is dependant on break size and location.

During the blow down phase of the LOCA, there is a net loss of coolant inventory, an increase in fuel cladding temperature due to core flow degradation and, for the larger breaks, the core becomes fully or partially uncovered. There is a rapid decrease in pressure during the blow down phase. During the early phase of the depressurization, the exiting coolant provides core cooling. The HPCS and LPCS systems also provide some heat removal. The blow down phase is defined to end when LPCS reaches rated flow. When the LPCS diesel generator is the single failure, the blow down phase end is defined as when LPCS, if operational, would have reached rated flow.

During single loop operation (SLO) the break may occur in either loop. The results of a break in the inactive loop would be similar to those from a break in two-loop operation. The break in the active loop during SLO results in a more rapid loss of core flow and earlier degraded core conditions.

In the LOCA refill phase, the ECCS is functioning and there is a net increase of coolant inventory. During this phase the core sprays provide core cooling and, along with LPCI, supply liquid to refill the lower portion of the reactor vessel. In general, the core heat transfer to the coolant is less than the fuel decay heat rate and the fuel cladding temperature continues to increase during the refill phase.

In the reflood phase, the coolant inventory has increased to the point where the mixture level reenters the core region. During the core reflood phase, cooling is provided above the mixture level by entrained reflood liquid and below the mixture level by pool boiling. Sufficient coolant eventually reaches the core hot node and the fuel cladding temperature decreases, terminating the event.

6.3.3.6.1 Loss-of-Coolant Accident Description

Immediately after the postulated double-ended recirculation suction line break, vessel pressure and core flow begin to decrease. The initial pressure response is governed by the closure of

the main steam isolation valves and the relative values of energy added to the system by decay heat and energy removed from the system by the initial blowdown of fluid from the downcomer. The initial core flow decrease is rapid because the recirculation pump in the broken loop loses suction and almost immediately ceases to pump. The pump in the intact loop coasts down relatively slowly. This pump coast down governs the core flow response for the next several seconds. When the jet pump suctions uncover, calculated core flow decreases to near zero. When the recirculation pump suction nozzle uncovers, the pressure begins to decay more rapidly. As a result of the increased rate of vessel pressure loss, the initially subcooled water in the lower plenum saturates and flashes up through the core, increasing the core flow. This lower plenum flashing continues at a reduced rate for the next several seconds.

Heat transfer rates on the fuel cladding during the early stages of the blowdown are governed primarily by the core flow response. Nucleate boiling continues in the high power plane until shortly after the core flow loss that results from jet pump uncovery. Film boiling heat transfer rates then apply, with increasing heat transfer resulting from the core flow increase during the lower plenum flashing period. Heat transfer then slowly decreases until the high power axial plane uncovers. At that time, convective heat transfer is assumed to cease.

Water level inside the shroud remains high during the early states of the blowdown because of flashing of the water in the core. After a short time, the level inside the shroud has decreased to uncover the core. Several seconds later, the ECCS is actuated. As a result the vessel water level begins to increase. Some time later the lower plenum is filled and the core is then rapidly recovered.

The cladding temperature at the high power plane decreases initially because nucleate boiling is maintained, the heat input decreases, and the sink temperature decreases. A rapid, short duration cladding heatup follows the time of boiling transition when film boiling occurs and the cladding temperature approaches that of the fuel. The subsequent heatup is slower, being governed by decay heat and core spray heat transfer. Finally the heatup is terminated when the core is recovered by the accumulation of ECCS water.

6.3.3.6.2 Loss-of-Coolant Accident Analysis Procedures and Input Variables

The GE Hitachi Nuclear Energy ECCS-LOCA licensing evaluation methodologies are described in References 6.3-7 through 6.3-14. The GE14 analysis is documented in Reference 6.3-5 and 6.3-15, consistent with References 6.3-1 and 6.3-2. The GNF2 analysis is documented in Reference 6.3-16, consistent with References 6.3-1, 6.3-2 and 6.3-5. These vendor methodologies cover the time from the event until the reactor has been reflooded. The NSSS vendor, GE, performed the long term ECCS evaluation, as described in Reference 6.3-7. The evaluation documents that the ECCS satisfy the requirements described in Section 6.3.3.2. As documented in Reference 6.3-1, the reactor power uprate and the new fuel did not impact the conclusions reached in Reference 6.3-7.

6.3.3.6.2.1 LOCA Analysis Methodology, GE Hitachi Nuclear Energy

Several computer models are used in the LOCA analysis to determine the LOCA response. These models are LAMB, TASC, PRIME, and SAFER (References 6.3-7 through 6.3-14). Together, these models evaluate the short-term and long-term reactor vessel blowdown response to a pipe rupture, the subsequent core flooding by ECCS, and the final rod heatup.

The LAMB model analyzes the short-term blowdown phenomena for postulated large pipe breaks in which nucleate boiling is lost before the water level drops sufficiently to uncover the active fuel. The LAMB output (primarily core flow as a function of time) is used in the TASC model for calculating blowdown heat transfer and fuel dryout time.

The TASC model completes the transient short-term thermal-hydraulic calculation for large recirculation line breaks. “TASC” is used to predict the time and location of boiling transition and dryout. The time and location of boiling transition is predicted during the period of recirculation pump coastdown. When the core inlet flow is low, TASC also predicts the resulting bundle dryout time and location. The calculated fuel dryout time is an input to the long-term thermal-hydraulic transient model, SAFER.

The PRIME model provides the parameters to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA for input to SAFER. PRIME also establishes the transient pellet-cladding gap conductance for input to both SAFER and TASC.

The SAFER model calculates the long-term system response of the reactor over a complete spectrum of hypothetical break sizes and locations. SAFER is compatible with the GESTR-LOCA fuel rod model for gap conductance and fission gas release. SAFER calculates the core and vessel water levels, system pressure response, ECCS performance, and other primary thermal-hydraulic phenomena occurring in the reactor as a function of time. SAFER realistically models all regimes of heat transfer that occur inside the core, and provides the heat transfer coefficients (which determine the severity of the temperature change) and the resulting PCT as functions of time. For GE11 and later fuel analysis with the SAFER code, the part length fuel rods are treated as full-length rods, which conservatively overestimate the hot bundle power.

6.3.3.6.2.2 Deleted.

6.3.3.6.2.3 LOCA Analysis Input Variables

The significant input variables used by the LOCA codes are listed in Table 6.3-1, Table 6.3-2a and Table 6.3-2b. The limiting calculation was performed at 3629 MWt (102.4% power) and 108.5 Mlb/hr (100% core flow), References 6.3-5 and 6.3-16. Alternate operating modes of SLO, increased core flow (ICF), reduced core flow (MELLLA) and reduced feedwater temperature (FFWTR/FWHOOS) have been confirmed as non-limiting.

6.3.3.7 Break Spectrum Calculations

Break spectrum analyses have been performed to establish the limiting break for the CGS boiling water reactor BWR5 reactor system. Previous analyses by GE, the NSSS vendor have shown that a large pipe break in the recirculation line on the suction side of the recirculation pump is the most limiting break for a BWR5. The GE analysis includes breaks in both recirculation and non-recirculation piping. Figure 6.3-9 shows the original plant break spectrum analysis for initial core fuel. For reload fuel, the break spectrum is determined and documented in Reference 6.3-5 (MELLLA), 6.3-15 (GE14) and 6.3-16 (GNF2), consistent with the original plant break spectrum analysis in References 6.3-1 and 6.3-7.

Two break types (geometry) are considered for the recirculation pipe break; the DEG break and the split break. For the DEG break, the pipe is completely severed, resulting in two independent flow paths to the containment. The DEG break is modeled by setting the break area equal to the full pipe cross-sectional area and varying the discharge coefficient. The split break is a longitudinal opening or hole that results in a single break flow path to the containment. Appendix K of 10 CFR 50 defines the cross-sectional area of the piping as the maximum split break area required for analysis.

6.3.3.7.1 Break Spectrum Calculation, GE Hitachi Nuclear Energy

A sufficient number of breaks for recirculation suction line are analyzed for GE14 with the potentially limiting single failures using nominal assumptions. This ensures that the limiting combination of break size, location, axial power shape and single failure has been identified. The limiting large break for nominal assumptions is the 100% DBA with mid-peaked axial power shape and HPCS DG failure. The overall limiting LOCA is the small recirculation suction line break of 0.07 ft^2 for nominal assumptions with top peaked axial power shape and HPCS DG failure.

Using the Appendix K input assumptions, analyses of large breaks are also performed with the limiting single failure. The 100%, 80%, and 60% DBA cases also satisfy the Appendix K requirement for using the Moody Slip Flow Model with three discharge coefficients of 1.0, 0.8, and 0.6, respectively. The limiting Appendix K case for large break is the 100% DBA with top-peaked axial power shape and HPCS DG failure. The overall limiting LOCA is the small recirculation suction line break of 0.07 ft^2 for Appendix K assumptions with top peaked axial power shape and HPCS DG failure.

The analysis also considers the non-recirculation line breaks (CS line, LPCI line and etc.) as well as alternate operating modes (MELLLA, ICF, FFWTR/FWHOOS and SLO) References 6.3-5, 6.3-15 and 6.3-16 documents all the analysis results.

6.3.3.7.2 Deleted.

6.3.3.8 Loss-of-Coolant Accident Analysis Conclusions

The ECCS will perform the required design functions and comply with 10 CFR 50.46 acceptance criteria.

The limiting large break for two loop operation is the recirculation suction line break of DBA with HPCS diesel generator failure at 102.4% rated power (3629 MWt)/100% rated flow conditions with a mid peaked axial power shape (References 6.3-5, 6.3-15 and 6.3-16).

The overall limiting LOCA is the small recirculation suction line break of 0.07 ft^2 for Appendix K and nominal assumptions, respectively, with high pressure core spray diesel generator failure at 102.4% rated power (3629 MWt)/100% rated flow conditions and a top peaked axial power shape (References 6.3-5, 6.3-15 and 6.3-16).

The SLO case is performed at the maximum attainable power and flow on the ELLLA rod line. The case conservatively assumes the simultaneous dryout of all axial fuel nodes almost immediately following the initiation of the event. A SLO multiplier of 1.0 on MAPLHGR is applied (References 6.3-5, 6.3-15 and 6.3-16). Extended operation in the MELLLA domain is not analyzed for SLO.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 Emergency Core Cooling System Performance Tests

The systems of the ECCS were tested for their operational ECCS function during the preoperational and/or startup test program. Each component was tested for power source, range, direction of rotation, set point, limit switch setting, torque switch setting, etc. Each pump was tested for flow capacity for comparison with vendor data (this test was also used to verify flow measuring capability.) The flow tests involved the same suction and discharge source; i.e., suppression pool or condensate storage tank.

All logic elements were tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

During preoperational tests each system was tested for response time and flow capacity while taking suction from its normal source and delivering flow into the reactor vessel.
See Section 14.2 for a thorough discussion of preoperational testing for these systems.
Pump and valve periodic tests are discussed in Section 3.9.6.

6.3.4.2 Reliability Tests and Inspections

Active components of the HPCS, ADS, LPCS, and LPCI systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a testing path back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested in accordance with Inservice Testing Program requirements. Input jacks are provided such that each ECCS loop can be tested for response time.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Section 8.3.1. The frequency of testing is prescribed by the Technical Specifications. Visual inspections of ECCS components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access to the drywell. When the reactor vessel is open, the spargers and other internals can be inspected.

6.3.4.2.1 High-Pressure Core Spray Testing

The HPCS can be tested at full flow with condensate storage tank water at any time during plant operation, except when the reactor vessel water level is low or when the condensate level in the condensate storage tanks is below the reserve level (135,000 gal) or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCS is being tested, the system automatically returns to the operating mode. The two motor-operated valves in the test line to the condensate storage system are interlocked closed when the suction valve from the suppression pool is open.

A design flow functional test of the HPCS over the operating pressure and flow range is performed by pumping water from the condensate storage tanks and back through the full flow test return line to the condensate storage tanks.

The suction valve from the suppression pool and the discharge valve to the reactor remain closed. These two valves are tested separately to ensure operability.

6.3.4.2.2 Automatic Depressurization System Testing

The ADS valves are fully tested during the time when the reactor is being depressurized prior to or repressurized following a refueling outage. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation. Each individual ADS valve is manually actuated.

During plant operation the ADS system can be checked as discussed in Section 7.3.1.

6.3.4.2.3 Low-Pressure Core Spray Testing

The LPCS pump and valves are tested periodically. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that of the LPCI valves.

6.3.4.2.4 Low-Pressure Coolant Injection Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in Chapter 5. During plant operation, this test does not inject cold water into the reactor because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. The injection line portion is tested with reactor water when the reactor is shut down and when a closed system loop is created. This prevents unnecessary thermal stresses.

To test an LPCI pump at rated flow, the test line valve to the suppression pool is opened and the pump suction valve from the suppression pool is opened (this valve is normally open). For loops A and B, the valve to the suppression chamber spray ring header is also opened. Correct operation is determined by observing the instruments in the control room.

If an initiation signal occurs during the tests, the LPCI system automatically returns to the operating mode. The valves in the test lines are closed automatically to ensure that the LPCI pump discharge is correctly routed to the reactor vessel.

6.3.5 INSTRUMENTATION REQUIREMENTS

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.1.

Instrumentation required for automatic and manual initiation of the HPCS, LPCS, LPCI, and ADS is discussed in Section 7.3.1 and is designed to meet the requirements of IEEE 279 and other applicable requirements. The HPCS, LPCS, LPCI, and ADS can be manually initiated from the control room.

The HPCS, LPCS, and LPCI are automatically initiated on low reactor water level or high drywell pressure (see Table 6.3-1 for specific initiation levels for each system). The ADS is automatically actuated by sensed variables for reactor vessel low water level plus indication that at least one RHR or LPCS pump is operating. The HPCS, LPCS, and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an initiation signal. The LPCS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure. HPCS injection begins as

soon as the HPCS pump is up to speed and the injection valve is open since the HPCS is capable of injecting water into the RPV over a pressure range from 0 psid* to 1160 psid.*

6.3.6 REFERENCES

6.3-1 GE Nuclear Energy, "Washington Public Power Supply System Nuclear Project 2, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," NEDC-32115P, Class III (Proprietary), DRF A00-05078, Revision 2.

6.3-2 GE Nuclear Energy, "Washington Public Power Supply System Nuclear Project 2, SRV Setpoint Tolerance and Out-of-Service Analysis," GE-NE-187-24-0992, Revision 2.

6.3-3 GE BWROG Committee on ECCS Suction Strainers, "Utility Resolution Guidance for ECCS Suction Strainer Blockage," NEDO-32686, Revision 0.

6.3-4 GE Nuclear Energy, Washington Public Power Supply System Nuclear Project 2, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, DRF A00-05078 and -05371.

6.3-5 GE Hitachi Nuclear Energy Report 0000-0105-1741-R0, "Energy Northwest Columbia Generating Station ARTS/MELLLA Task T0407: ECCS-LOCA Evaluations," October 2009.

6.3-6 GE Hitachi Nuclear Energy Report 002N5109-R0, "Columbia Long Term Cooling," May 26, 2015.

6.3-7 General Electric Company, "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K," NEDO-20566-A, September 1986.

6.3-8 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 1, GESTR-LOCA – A Model for the Prediction of Fuel Rod Thermal Performance," NEDE-23785-1-PA, Revision 1, October 1984.

6.3-9 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 2, SAFER – Long Term Inventory Model for BWR Loss-of-Coolant Analysis," NEDE-23785-1-PA, Revision 1, October 1984.

6.3-10 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 3, SAFER/GESTR– Application Methodology," NEDE-23785-1-PA, Revision 1, October 1984.

* psid - differential pressure between RPV and pump suction source.

6.3-11 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 3, Supplement 1, Additional Information for Upper Bound PCT Calculation," NEDE-23785P-A, Revision 1, March 2002.

6.3-12 "TASC-03A A Computer Program for Transient Analysis of a Single Channel," NEDC-32084P-A, Revision 2, July 2002.

6.3-13 "Compilation of Improvements to GENE's SAFER ECCS-LOCA Evaluation Model," NEDC-32950P, Revision 1, July 2007.

6.3-14 "The PRIME Model for Analysis of Fuel Rod Thermal-Mechanical Performance," Part 1 – Technical Bases – NEDC-33256P-A, Part 2 – Qualification – NEDC-33257P-A, and Part 3 Application Methodology – NEDC-33258P-A, Revision 1, September 2010.

6.3-15 "Columbia Generating Station GE14 ECCS-LOCA Evaluation," GE Hitachi Nuclear Energy, 0000-0090-6853-R0, February 2009.

6.3-16 "Columbia Generating Station GNF2 ECCS-LOCA Evaluation," 001N0373-R2, February 2015.

6.3-17 GE-Hitachi Nuclear Energy, "Safety Analysis Report for Columbia Generating Station Thermal Power Optimization," NEDC-33853P, March 2016.

Table 6.3-1

Emergency Core Cooling System Design Parameters

Parameter	Value	
Initiation Signals		
High drywell pressure	2.0 psig (not credited)	
L2 (Low low water level)	9.26 ft above top of active fuel	
L1 (Low low low water level)	2.68 ft. above top of active fuel	
LPCS pump running	150 psig pump discharge pressure	
LPCI pump running	100 psig pump discharge pressure	
High Pressure Core Spray System		
Minimum rated flow at vessel pressure (differential pressure between vessel head and suction source)	psid	gpm
	200	6350
	1130	1550
	1160	516
Vessel pressure that injection valve may open	1175 psia	
Maximum flow (runout)	7341 gpm	
Low Pressure Core Spray System		
Minimum rated flow at vessel pressure (differential pressure between vessel head and suppression pool air volume)	psid	gpm
	128	6350
Vessel pressure that injection valve may open	485 psia	
Maximum flow (runout)	8100 gpm	
Low Pressure Coolant Injection Mode RHR System		
Minimum rated flow at vessel pressure (differential pressure between vessel head and suppression pool air volume)	psid	gpm
	26	7450
Vessel pressure that injection valve may open	485 psia	
Maximum flow (runout) three pumps	24100 gpm	
Automatic Depressurization System		
Number of safety relief valves with ADS function	7 valves	
Time delay: - Initiation signal to valves open	105 seconds[a]	

[a] Either of both ADS trip systems may be manually inhibited, if necessary, to eliminate resetting the timer.

Table 6.3-2a

Plant Operational Parameters

Parameter	Nominal Assumption	Appendix K Assumption
Rated Case Core Thermal Power (MW)	3629	3702
Rated Case Core Flow (Mlbm/hr)	108.5	108.5
MELLLA Case Core Thermal Power (MW)	3629	3702
MELLLA Case Core Flow (Mlbm/hr)	93.04	93.04
ELLLA SLO Case Core Thermal Power (MW)	2684.2	2737.9
ELLLA SLO Case Core Flow (Mlbm/hr)	61.845	61.845
Vessel Steam Dome Pressure (psia)	1055	1055
Feedwater Temperature (°F)	425.7	428
PLHGR Uncertainty (%)	N/A	2
Number of ADS Valves Assumed Available	5	5
Feedwater Temperature Reduction (°F)	65[1]	65[1]
ICF Core Flow (Mlbm/hr)	115	115

[1] Feedwater temperature: Nominal - 65°F or 355°F, whichever is lower.

Table 6.3-2b

Fuel Parameters

Parameter		GE14	GNF2
PLHGR (kW/ft)	– LOCA Analysis Limit	13.40	14.40
	– Appendix K	13.40 × 1.02	14.40 × 1.02
	– Nominal	12.80	13.75
MAPLHGR (kW/ft)	– LOCA Analysis Limit	12.82	13.78
	– Appendix K	12.82 × 1.02	13.78 ×1.02
	– Nominal	12.24	13.15
Peak Pellet Exposure (MWd/MTU)		16,000	14600
Initial Operating MCPR	– LOCA Analysis Limit	1.25	1.25
	– Appendix K	1.25 ÷ 1.02	1.25 ×1.02
	– Nominal	1.25 + 0.02	1.25 + 1.02
Fueled Rods per Assembly		92	92

Table 6.3-2c

ECCS Parameters

Low Pressure Coolant Injection (LPCI) System		
Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	222
b. Minimum rated flow (into shroud)		
• Vessel pressure at which below listed flow rates are quoted	psid (vessel to drywell)	20
• One (1) LPCI pump injecting inside shroud	gpm	6,713
• Two (2) LPCI pumps injecting inside shroud	gpm	13,426
• Three (3) LPCI pumps injecting inside shroud	gpm	20,139
c. Run-out flow at 0 psid (vessel to drywell)		
• One (1) LPCI pump injecting inside shroud	gpm	7,034
• Two (2) LPCI pumps injecting inside shroud	gpm	14,068
• Three (3) LPCI pumps injecting inside shroud	gpm	21,102
d. Initiating signals		
• Low low low water level (Level 1)	inches above vessel “zero”	378.5
e. Vessel pressure at which injection valve may open	psig	336
f. Maximum delay time from pump start until pump is at rated speed	sec	26
g. Maximum injection valve stroke time-opening	sec	26
h. Delay time to process initiation signal	sec	5

Table 6.3-2c

ECCS Parameters
(Continued)

Low Pressure Core Spray (LPCS) System		
Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	285
b. Minimum rated flow at vessel-to-drywell pressure (into shroud)	gpm psid	5625 122
c. Run-out flow at 0 psid (vessel to drywell)	gpm	7030
d. Initiating signals		
• Low low low water level (Level 1)	inches above vessel “zero”	378.5
e. Vessel pressure at which injection valve may open	psig	336
f. Maximum delay time from pump start until pump is at rated speed	sec	7
g. Maximum injection valve stroke time-opening	sec	22
h. Delay time to process initiation signal	sec	5

Table 6.3-2c

ECCS Parameters
(Continued)

High Pressure Core Spray (HPCS) System		
Variable	Units	Analysis Value
a. Vessel Pressure at which flow may commence	psid (vessel to source)	1160
b. Minimum rated flow and vessel pressure	gpm/psid (vessel to source of suction)	413/1160 920/1130 5000/200 6250/0
c. Run-out flow at 0 psid (vessel to source of suction)	gpm	6250
d. Initiating signals		
• Low low water level (Level 2)	inches above vessel "zero"	437.5
e. Maximum delay time from pump start until pump is at rated speed	sec	7
f. Maximum injection valve stroke time-opening	sec	17
g. Delay time to process initiation signal	sec	5

Table 6.3-2c

ECCS Parameters
(Continued)

Automatic Depressurization System (ADS)		
Variable	Units	Analysis Value
a. Total number of valves with ADS function available		7
b. Number of ADS valves assumed in the analysis		5
c. Pressure at which below listed capacity is quoted	psig	1205
d. Minimum flow capacity at pressure given in c with all available ADS valves open	lbm/hr	9.0×10^5
e. Initiating Signals		
• Low low low water level (Level 1) and	inches above vessel “zero”	378.5
• ADS Timer Delay from initiating signal completed to the time valves are open	sec	120
f. Delay time to process initiation signal	sec	5

Table 6.3-3

Single Failure Considered in ECCS Performance Evaluation

Break Location	Assumed Failure[1]	Systems Remaining[2] [3]
Recirculation Suction Line	LPCI Emergency D/G	ADS, HPCS, LPCS, 1 LPCI
Recirculation Suction Line	LPCS Emergency D/G	ADS, HPCS, 2 LPCI
Recirculation Suction Line	HPCS Emergency D/G	ADS, LPCS, 3 LPCI
Core Spray Line	LPCS Emergency D/G	ADS, 2 LPCI
Steamline Inside Containment	LPCI Emergency D/G	ADS, HPCS, LPCS, 1 LPCI
Steamline Outside Containment	HPCS Emergency D/G	ADS, LPCS, 3 LPCI
Feedwater Line	HPCS Emergency D/G	ADS, LPCS, 3 LPCI
LPCI Line	HPCS Emergency D/G	ADS, LPCS, 2 LPCI

[1] Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures.
[2] Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.
[3] The analyses are performed with two non-function ADS valves in addition to the single failure.

Table 6.3-4a

Event Scenario for 100% DBA Recirculation Suction Line Break
HPCS DG Failure (Appendix K)

Event	GNF2 Time (sec)	GE14 Time (sec)
Break Occurs	0.00	0.0
Scram Initiated and Occurs	0.01	0.01
Level 1 Trip	4.88	4.97
Feedwater Flow Reaches Zero	4.00	5.00
First Peak PCT Occurs	6.90	5.50
Jet Pump Suction Uncovers	5.94	5.98
Main Steamline Flow Stops	6.66	6.14
Suction Line Uncovers	8.76	8.54
Lower Plenum Flashes	9.61	9.15
LPCS/LPCI IV Pressure Permissive Reached	30.53	30.45
LPCS Injection Occurs	57.53	57.45
LPCI Injection Occurs	61.53	61.45
Second Peak PCT Occurs	142.50	148.18

Table 6.3-4b

Event Scenario for 0.07 ft^2 Recirculation Suction Line Break
HPCS DG Failure (Appendix K)

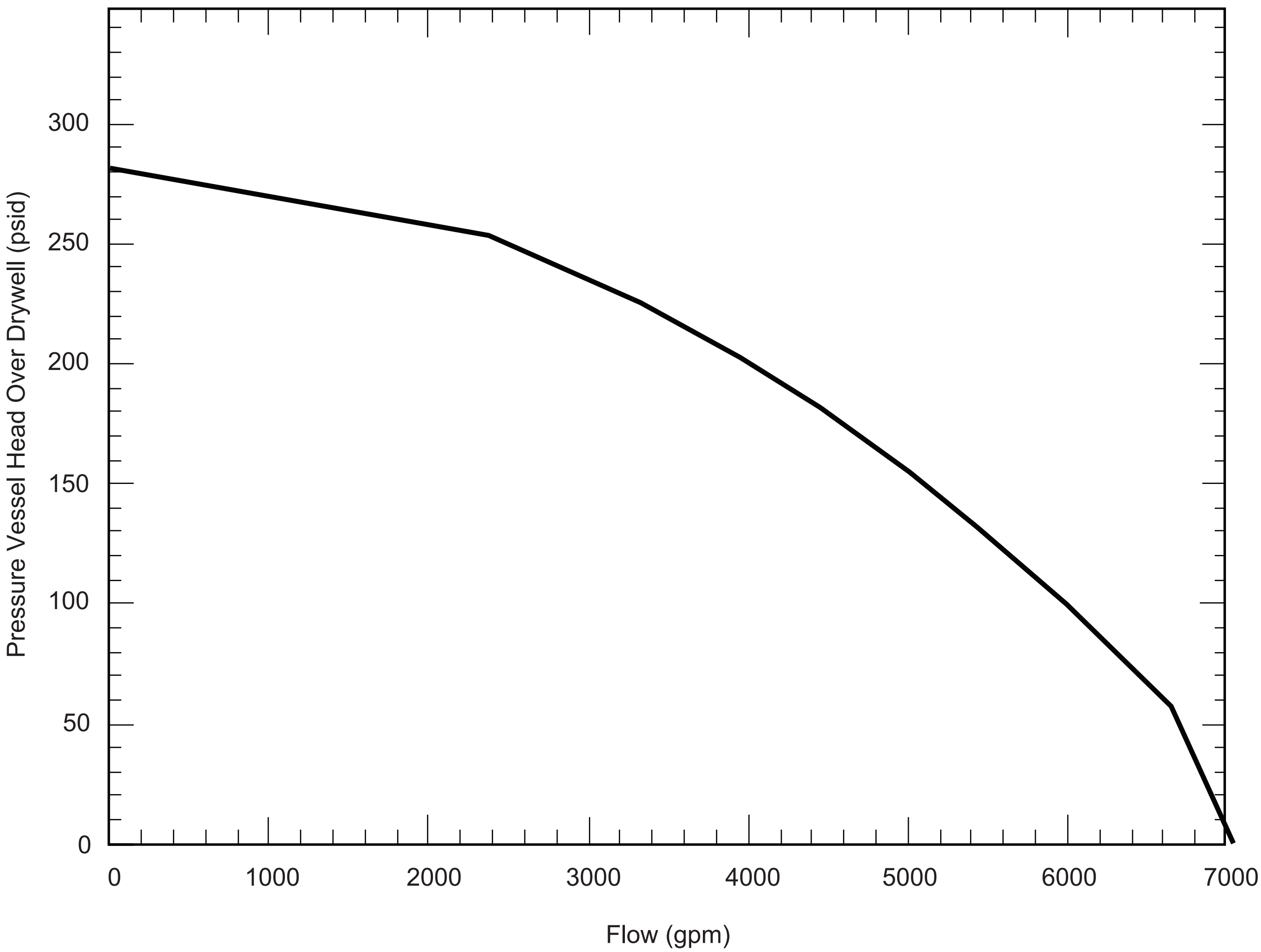
Event	GNF2 Time (sec)	GE14 Time (sec)
Break Occurs	0.00	0.0
Scram Initiated and Occurs	0.01	0.01
Feedwater Flow Reaches Zero	4.00	5.00
Level 1 Trip	107.23	114.50
SRVs Open	170.02	178.47
Jet Pump Suction Uncovers	212.86	221.47
ADS Valves Open	232.23	239.50
Main Steamline Flow Stops	240.12	246.99
Lower Plenum Flashes	242.98	248.61
Suction Line Uncovers	366.89	369.46
LPCS/LPCI IV Pressure Permissive Reached	384.79	394.23
LPCS Injection Occurs	411.79	421.23
LPCI Injection Occurs	415.79	425.23
Peak PCT Occurs	445.67	450.81

Table 6.3-5

ECCS Performance Analysis Results

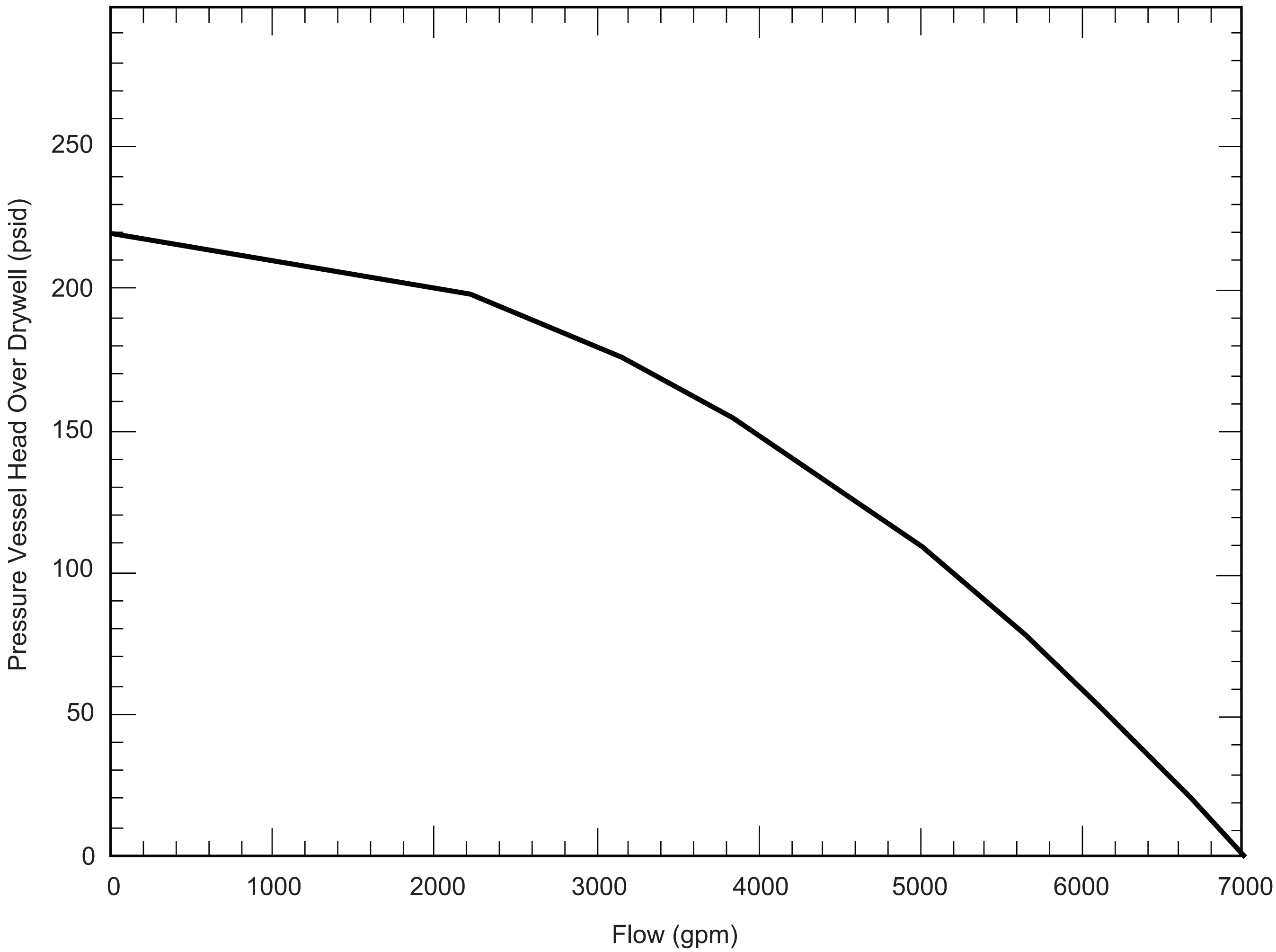
Parameter	GE14 Value		GNF2 Value	
	Two loop operation	Single loop operation	Two loop operation	Single loop operation
Thermal power (including .34% power uncertainty)	104.5% rated power (3702 MWt)	77.3% rated power *(2737.9 MWt)	104.5% rated power (3702 MWt)	77.3% rated power *(2737.9 MWt)
Core flow	100% rated flow (108.5 Mlb/hr)	57% rated flow (61.845 Mlb/hr)	100% rated flow (108.5 Mlb/hr)	57% rated flow (61.845 Mlb/hr)
Limiting break	0.07 ft^2 Recirculation suction line, HPCS DG failure	100% DBA Recirculation suction line, HPCS DG failure	0.07 ft^2 Recirculation suction line, HPCS DG failure	100% DBA Recirculation suction line, HPCS DG failure
Peak cladding temperature (Appendix K)	1647°F	1210°F	1637°F	1316°F
Licensing basis peak cladding temperature	1710°F		1700°F	
Maximum cladding oxidation	≤ 1%		≤ 1%	
Total core hydrogen generation	≤ 0.1%		≤ 0.1%	

*Single Loop Operation is based upon the nominal power rating (2684.2 MWt) which is 2% less than rated power. 2684.2 MWt is 75.7% of rated power.



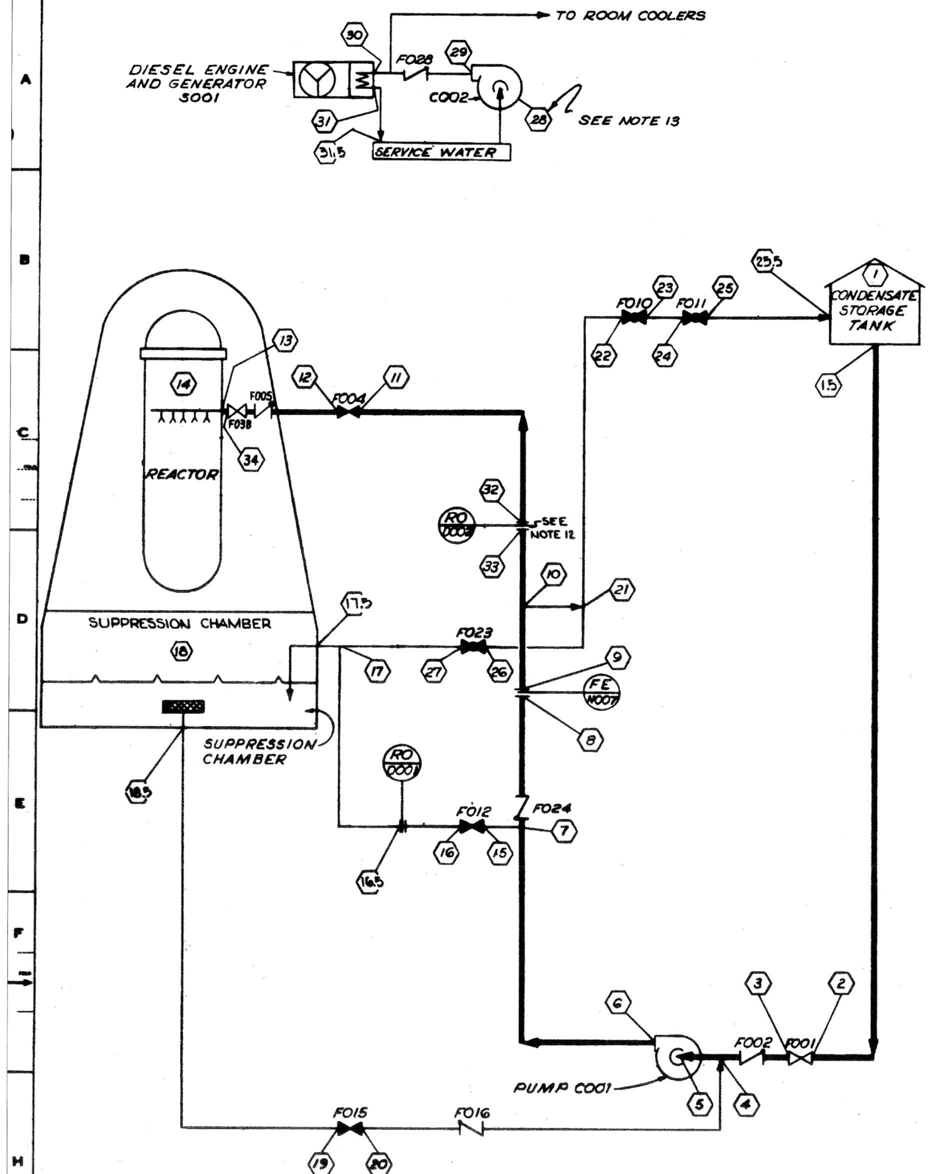
Head Versus Low-Pressure Core Spray Flow used in LOCA Analysis

Draw. No. 960222.13 | Rev. | Figure 6.3-1



Head Versus Low-Pressure Coolant Injection Flow used in LOCA Analysis

Draw. No. 960222.14 | Rev. | Figure 6.3-2



PRIMARY MODES

(SEE NOTE 21)

MODE A ACCIDENT OR RCIC BACKUP, REACTOR AT HIGH PRESSURE, SUCTION FROM CONDENSATE STORAGE

POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	1550	←									→	1550	N/A
PRESS. PSIA	14.7													1145
TEMP °F	AMB	120/40	←									→	120/40	AMB.
MAX. PRESS. DROP FEET					←2787→									

(SEE NOTE 21)

MODE B ACCIDENT, REACTOR AT HIGH PRESSURE, SUCTION FROM SUPPRESSION POOL

POSITION	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM	1550	←							→	1550	N/A	1550	1550	N/A
PRESS. PSIA											1145			14.7
TEMP °F	120/40	←							→	120/40	AMB	120/40	120/40	AMB
MAX. PRESS. DROP FEET		←2787→												

MODE C ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY, SUCTION FROM SUPPRESSION POOL

POSITION	4	5	6	7	8	9	10	11	12	13	14	19	20	18	28	29	30	31
FLOW GPM	6350	←							→	6350	N/A	6350	6350	N/A	←1200→		←1000→	
PRESS PSIA											215			14.7	SEE NOTE 13			
TEMP °F	170/40	←							→	170/40	AMB	170/40	170/40	AMB	←95→			
MAX. PRESS. DROP FEET		←865→			←21→			←2.2→		←198→		←.30→			←123→		←14→	

MODE D ACCIDENT, SYSTEM INJECTION AT RATED CORE FLOOD, SUCTION FROM SUPPRESSION POOL

POSITION	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM	6856	←							→	6856	N/A	6856	6856	N/A
PRESS. PSIA											41		-	14.7
TEMP °F	170/40	←							→	170/40	AMB	170/40	170/40	AMB
MAX. PRESS. DROP FEET		←594→			←24→			←2.5→		←231→				

MODE E ACCIDENT, SYSTEM INJECTION AT RATED CORE FLOOD, SUCTION FROM CONDENSATE STORAGE

POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM SEE NOTE 5 & 8	N/A	6856	←									→	6856	N/A
PRESS PSIA	14.7				SEE NOTE 8									80
TEMP. °F	AMB	120/40	←									→	120/40	AMB
MAX. PRESS. DROP FEET		←.79→			←594→ SEE NOTE 6			←24→			←2.5→		←231→	

MODE F ACCIDENT, SYSTEM OPERATING AT RUNOUT, SUCTION FROM SUPPRESSION POOL

POSITION	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM SEE NOTE 9.	7175/7300	←							→	7175/7300	N/A	7175/7300	7175/7300	N/A
PRESS. PSIA		SEE NOTE 7									14.7			14.7
TEMP °F	212/40	←							→	212/40	AMB	212/40	212/40	AMB
MAX. PRESS. DROP FEET		←437→										←.4→		

SEE NOTE 27

MODE G SYSTEM TEST, SUCTION FROM SUPPRESSION POOL

POSITION	4	5	6	7	8	9	10	21	26	27	17	19	20	18
FLOW GPM SEE NOTE 9	7175/7300	←										→	7175/7300	N/A
PRESS. PSIA														14.7
TEMP °F	120/40	←										→	120/40	AMB
MAX. PRESS. DROP FEET		←437→							←59→ SEE NOTE 10					

SEE NOTE 27

TABLE I
VALVE POSITION TABLE

VALVE	F001	F004	F010	F011	F012	F015	F023	F038
MODE A	O	O	C	C	C	C	C	O
MODE B	C	O	C	C	C	O	C	O
MODE C	C	O	C	C	C	O	C	O
MODE D	C	O	C	C	C	O	C	O
MODE E	O	O	C	C	C	C	C	O
MODE F	C	O	C	C	C	O	C	O
MODE G	C	C	C	C	C	O	O	O
MODE H	O	C	O	O	C	C	C	O
MODE J	O	C	C	C	O	C	C	O
MODE S	O	C	C	C	C	C	C	O
MODE CC	C	O	C	C	O	O	C	O

O VALVE OPEN
C VALVE CLOSE

MODE J PUMP OPERATING ON BYPASS, SUCTION FROM CONDENSATE STORAGE

POSITION	1	2	3	4	5	6	7	15	16	17	18
FLOW GPM	N/A	1150	←						→	1150	N/A
PRESS. PSIA	14.7										14.7
TEMP. °F	AMB	120/40	←						→	120/40	AMB
MAX. PRESS. DROP FEET					←3000→			←65→			

LOCATION	1.5 2	4 18.5 4 5
DESIGN TEMP (°F)	140 / 212	212
DESIGN PRESS (PSIG)	100	100
ESTIMATED LINE SIZE (IN.)	14	18
	CONDENSATE STG SUCTION LINE	SUPPRESSION POOL SUCTION LINE

NOTES:

1. ALL EMPTY PRESSURE DATA BLANKS CAN BE FILLED IN BY OTHER (BASED ON ACTUAL ARRAGNEMENT) OR EQUIV. HYDRAULIC DATA SU MITTED TO APED FOR REVIEW. ☒ INDICATES THE DATA IS SIGNIFICANT.
2. MAX/MIN INDICATES MAXIMUM & MINIMUM VALUE OF PARAMETER THE MODE SPECIFIED.
3. ELEVATIONS ARE NOT INCLUDED IN ΔP VALUES GIVEN. ELEVATIO SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY PRESSURE DATA BLANKS.
4. THE PUMP MAXIMUM SHUTOFF HEAD WILL NOT EXCEED 3450 FT.
5. IN MODE E WITH A PUMP TDH OF 865 FT AND A VESSEL PRESSUR OF 215 PSIA THE FLOW MUST BE EQUAL TO OR GREATER THAN 6350 GPM.
6. THE PUMP TDH GIVEN FOR MODE E IS BASED ON A MAXIMUM CON-TAINMENT PRESSURE OF 45 PSIG. BWRSD MUST BE ADVISED IF TH CONTAINMENT DESIGN IS BASED ON A HIGHER PRESSURE AND THE IMPACT ON THE HIGH PRESSURE CORE SPRAY SYSTEM EVALUATED.
7. IN MODE F THE NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE AT THE CENTER LINE OF THE PUMP SUCTION NOZZLE MUST EQUAL OR EXCEED 32.2 FEET.
8. IN MODE E AND AT A FLOW RATE OF 7349 GPM OR LESS, THE AVAILABLE NPSH MUST EQUAL OR EXCEED THE VALUE SPECIFIED IN NOTE 7 .
9. THE FLOW SPECIFIED FOR MODES F AND G IS APPROXIMATE AND BE DETERMINED BASED ON FINAL SYSTEM DESIGN. THE FLOW GIV FOR THESE MODES IS THE MAXIMUM ALLOWABLE.
10. THE ΔP GIVEN FOR THE VALVES IN MODES G AND H IS THE MINI POSSIBLE AND MAY BE INCREASED BY OTHERS (THROTTLING) TO ACCOMMODATE PIPING ARRANGEMENT.
11.
12. ORIFICE RO-2 PROVIDES NO RESTRICTION, AS ITS BORE COINCIDES WITH THE INNER DIAMETER OF THE 16" DISCHARGE HEADER. THE SYSTEM RESISTANCE-WITHOUT RES IS SUFFICIENT TO ENSURE PUMP RUN OUT WILL NOT EXCEED SPECIFIED LIMITS.
13. THE MIMIMUM AVAILABLE NPSH TO THE DIESEL SERVICE WATER P MUST BE 22 FT OR GREATER.
14. VALUES WILL BE ADDED FOR INDIVIDUAL PROJECT BASED ON AC COOLING WATER TEMPERATURE.
15.
16. ΔP VALUES FOR EQUIPMENT WITHIN GE-APED SCOPE ARE AS NOTE
17. TABLE I INDICATES VALVE POSITION DURING VARIOUS OPERATIN MODES.
18. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ES IMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIG TEMPERATURE AND PRESSURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DIAGRAM HYDRAULIC REQUIRE
19.
20. IN MODE E AND WITH A VESSEL PRESSURE OF 14.7 PSIA, THE FI SHALL NOT EXCEED 7175/7300 GPM (SEE NOTE 27).
21. FOR MODES A & B, ONE THIRD OF TABULATED FLOW SHALL BE DEL TO THE VESSEL WITH REACTOR VESSEL PRESSURE AT 1175 PSI THE LOW FLOW BYPASS VALVE (E22-F012) OPEN.
22. THE FLOW SPECIFIED FOR MODE CC MUST BE EQUALED OR EXCE WITH THE SUCTION FROM THE CONDENSATE STORAGE SYSTEM WITH THE REACTOR PRESSURE EQUAL TO 1225 PSIA.
23. CAUTION: TO AVOID PUMP DAMAGE/FAILURE, THE MAXIMUM RUNOUT FLOW PUMP OPERATING MODE (e.g. PREOPERATION TEST, PRELIMINARY PUMP CHECK AND ALL MODES ON THE PROCESS DIAGRAM) SHALL NOT EXCEED 7175/7300 GPM THE MINIMUM FLOW SHALL NOT BE BELOW 1150 GPM.

(NOTES CONT'D. TO ZONE M/1)

SUPPLEMENTAL DOCUMENTS UNDER THE FOLLOWING IDENTITIES ARE TO BE USED IN CONJUNCTION WITH THIS DRAWING.

	REFERENCE DESIGNATOR
1. HIGH PRESSURE CORE SPRAY P&ID	E22-1010
2. NUCLEAR BOILER SYSTEM PROC. DIA	B22-1020
3. H	

NOTES (CONT'D FROM ZONE J/11)

24. ONLY MODE CC WAS UPDATED FOR RPU. THIS WAS CONSIDERED THE MOST AFFECTED AND LIMITING MODE FOR RPU.
25. MAX. PRESS DROP FEET VALUES ARE APPROXIMATE. REFER TO DESIGN CALCULATIONS FOR ACTUAL VALUES.
26. FOR MODES D AND E, THE FLOWS INDICATED ARE APPROXIMATE. REFER TO DESIGN CALCULATIONS FOR ACTUAL VALUES.
27. 7175 GPM WITH MODEL 12X20KD-8 HPCS-P-1 PUMP INSTALLED. 7300 GPM WITH MODEL 10154123 HPCS-P-1 PUMP INSTALLED. THE MAXIMUM BOUNDING FLOW PER ANALYSIS IS 7349 GPM.

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High-Pressure Core Spray - Process Diagram

Draw. No. 02E22-04,7,1 | Rev. 7 | Figure 06.3-3.1

MODE H SYSTEM TEST. SUCTION FROM CONDENSATE STORAGE

POSITION ○	1	2	3	4	5	6	7	8	9	10	21	22	23	24	25
FLOW GPM	N/A	[illegible]													[illegible]
PRESS PSIA	14.7														
TEMP °F	AMB	[illegible]/40													[illegible]/40
MAX PRESS DROP FEET					594							95 SEE NOTE 10		95 SEE NOTE 10	

MODE S SYSTEM ON STANDBY DUTY

POSITION ○	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	0											0	N/A
PRESS PSIA	14.7													SEE REF 2
TEMP °F	AMB	[illegible]/40								[illegible]/40	AMB			AMB
MAX PRESS DROP FEET					0									

MODE CC ACCIDENT OR RCIC BACK-UP, REACTOR AT HIGH PRESSURE (SEE NOTE 22), SUCTION FROM THE SUPPRESSION POOL

POSITION ○	18.5	19	20	4	5	6	7	8	9	10	11	12	13	14	15	16	17	17.5	18
FLOW GPM				1563						413				N/A		1150			N/A
PRESS PSIA														1225					14.7
TEMP °F	140/40												140/40	AMB	140/40			140/40	AMB
MAX PRESS DIFFERENCE FT					3025											6.5			

TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENT
F	18.5-19-20-4-5	SEE NOTE 7
È	1.5-2-3-4	SEE NOTE 8
CORE	6-7-8-9-10-11-12-13	SEE NOTE 5
J	7-15-16-16.5-17	
H	10-21-22-23-24-25-25.5	
G	21-26-27-17-17.5	

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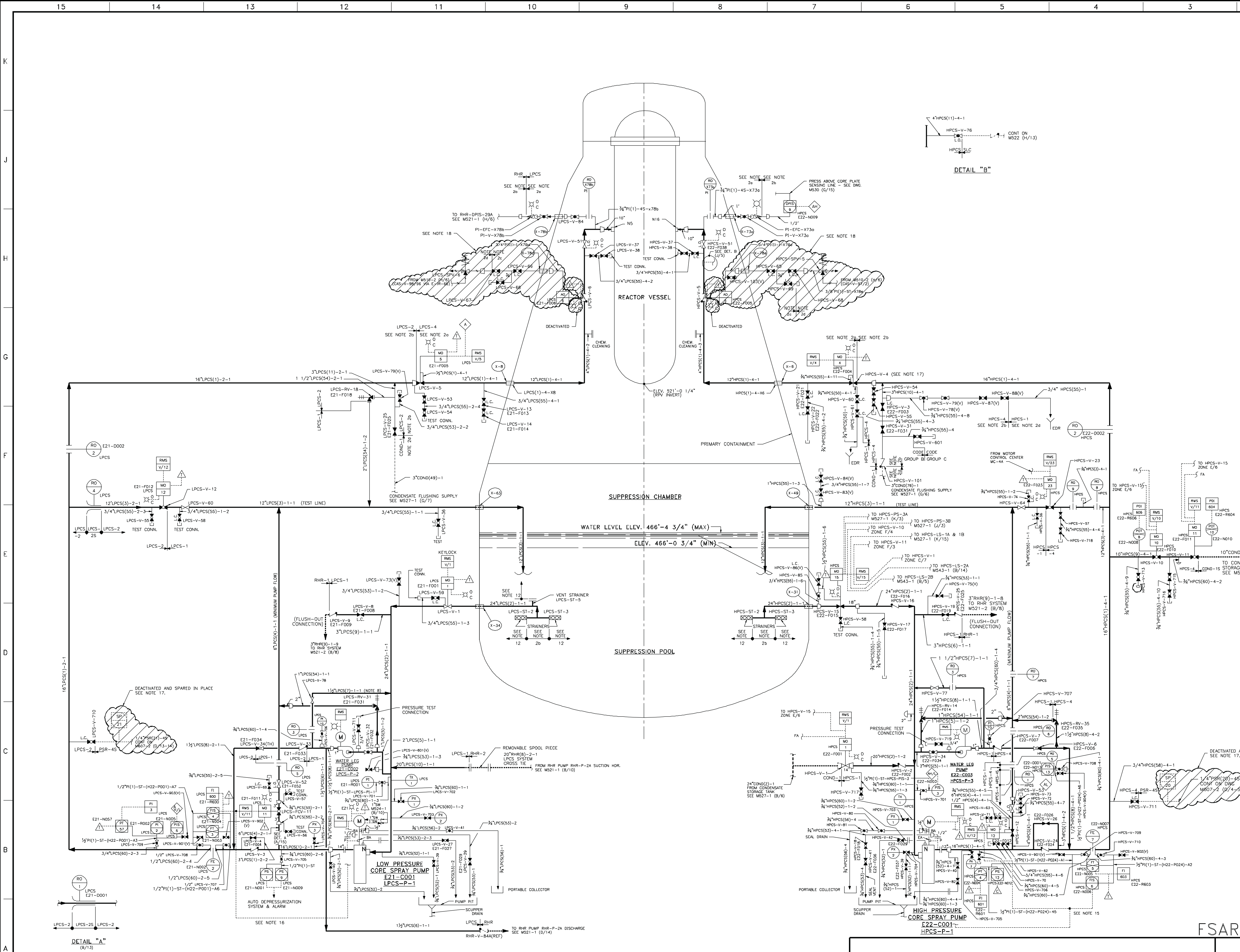
High-Pressure Core Spray - Process Diagram

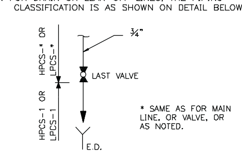
Draw. No. 02E22-04,7,2 Rev. 5 Figure 6.3-3.2

Form No. 960690



NOTES

1. ALL INSTRUMENT ROOT VALVES NOT LABELED WILL BE 3/4" GLOBE VALVES UNLESS SPECIFICALLY NOTED OTHER WISE.
2. PIPING, VALVES AND ASSOCIATED COMPONENTS ON THIS DRAWING SHALL BE CLASSIFIED AS FOLLOWS EXCEPT AS STATED IN NOTES 12 & 13: (BREAK POINTS ARE INDICATED ON FLOW DIAGRAM)
   a. PIPING AND VALVES OUT THROUGH OUTERMOST REACTOR ISOLATION VALVES
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP A
   b. PIPING AND VALVES BEYOND OUTERMOST REACTOR ISOLATION VALVES PLUS ALL INSTRUMENT LINES, EXCEPT THE PUMP SEAL DRAIN LINES DESIGNATED AS 3/4" LPCS(56)-2 AND 3/4"HPCS(56)-4
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B
   c. INSTRUMENTATION AIR LINES AND LEAK-OFF PIPING INSIDE CONTAINMENT ISOLATION VALVE:
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B
   d. INSTRUMENTATION AIR LINES AND LEAK-OFF PIPING OUTSIDE CONTAINMENT ISOLATION VALVE: AND THE PUMP SEAL DRAIN LINES DESIGNATED 3/4"LPCS(56)-2 AND 3/4"HPCS(56)-4 AND OTHER PIPING AND VALVES DESIGNATED BY THIS NOTE
      SEISMIC CATEGORY II ⊕
      QUALITY CLASS II
      CODE GROUP D
      } Ø
      ⊕ HANGERS TO BE DESIGNED TO SEISMIC CATEGORY I LOADS.
      Ø EXCEPT AS NOTED ON M619 INSTR. CONN. DIAG.
3. FOR DRAIN OR LEAK-OFF LINES, THE PIPING CLASSIFICATION IS AS SHOWN ON DETAIL BELOW.



4. DELETED
5. DELETED
6. ALL PIPING SYSTEMS IDENTIFIED BY THE PREFIX "PI" SHALL BE SUPPLIED AND INSTALLED BY CONTRACT #220.
7. DELETED
8. ALLOWED ADEQUATE PIPING SURFACE AREA FOR COOLING OF PUMP LPCS-P-2.
9. DELETED
10. DELETED
11. DELETED
12. PIPING, VALVES AND ASSOCIATED COMPONENTS ON THIS DRAWING SHALL BE CLASSIFIED AS FOLLOWS (BREAK POINTS ARE INDICATED ON THIS DIAGRAM)
    SIESMIC CATEGORY I
    QUALITY CALSS I
    CODE GROUP B*
    *ASME III/2 WITH EXCEPTIONS. SEE PROCUREMENT SPECIFICATION 12023.
13. ALL PIPING DOWNSTREAM OF THE LAST ISOLATION VALVE AND OPEN TO THE ATMOSPHERE WITH THE SUBSYSTEM DESIGNATION SYSTEM (50) THROUGH (59) SHALL BE CLASSIFIED AS CODE GROUP D WITH QUALITY CLASS AND SEISMIC CATEGORY PROVIDED BY THE APPLICABLE NOTES ON THIS DRAWING.
14. ALL INSTRUMENT LINES ARE DESIGNATED BY CODE AND LINE NUMBER, EXAMPLES;
    A. LINE ORIGINATING OUTSIDE CONTAINMENT.
       $\underbrace{\text{1/2"PI(1)-4S}}_{\text{CODE DESIGNATION}}\text{-}\underbrace{\text{(H22-P021)-A6}}_{\text{LINE NO.}}$
    B. LINES ORIGINATING INSIDE CONTAINMENT.
       $\underbrace{\text{1/2"PI(1)-4S-}}_{\text{CODE DESIGNATION}}\ \underbrace{\text{X106}}_{\text{LINE NO.}}$
    C. CONTINUATION OF THE ABOVE LINE OUTSIDE CONTAINMENT IS DESIGNATED AS FOLLOWS W/LINE NUMBERS NOT SHOWN.
       $\underbrace{\text{1/2"PI(1)-ST-X106}}_{\text{LINE DESIGNATION}}\text{-}\underbrace{\text{(H22-P021)}}_{\text{LINE NO.}}$
15. FOR DETAILED WIRING SEE EWD-7E-0023.
16. FOR DETAILED WIRING SEE EWD-8E-0008.
17. SAMPLE POINT IS NO LONGER FUNCTIONAL. ALTERNATE METHOD OF SAMPLING IS DONE PER THE APPLICABLE PPM.
18. AIR OPERATOR AND AIR SUPPLY FOR TESTABLE CHECK VALVES HPCS-V-5 AND LPCS-V-6 ARE DEACTIVATED AND SPARED IN PLACE. THESE VALVES ARE TESTED PER THE IST PROGRAM. PENETRATION AND ISOLATION/TEST VALVES ARE STILL ACTIVE.
19. SEE DWG M501 FOR FLOW DIAGRAM LEGENDS, SYMBOLS AND ABBREVIATIONS.

LEGEND

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE EXCEPT AS NOTED.
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

FSAR FIG.

Columbia Generating Station
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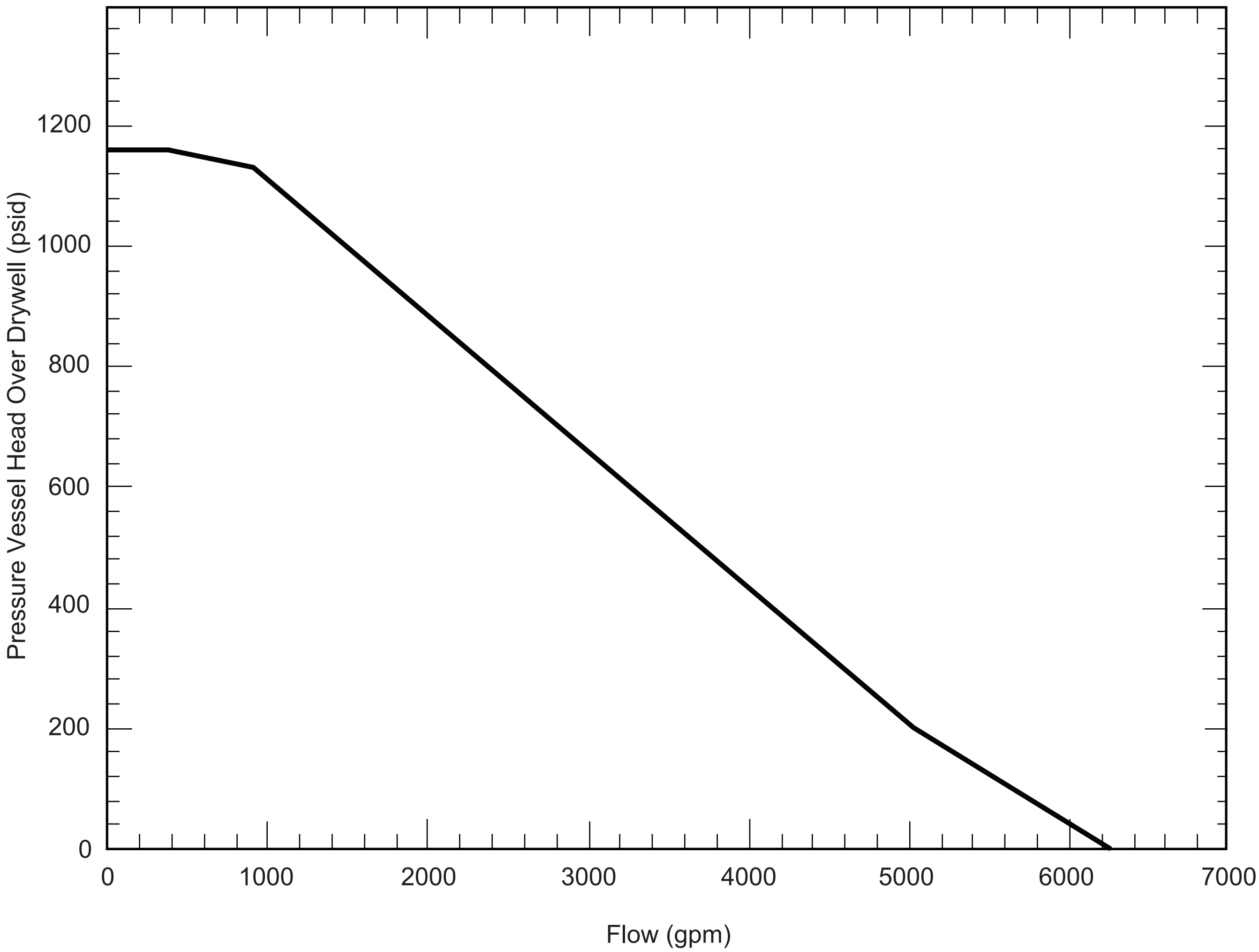
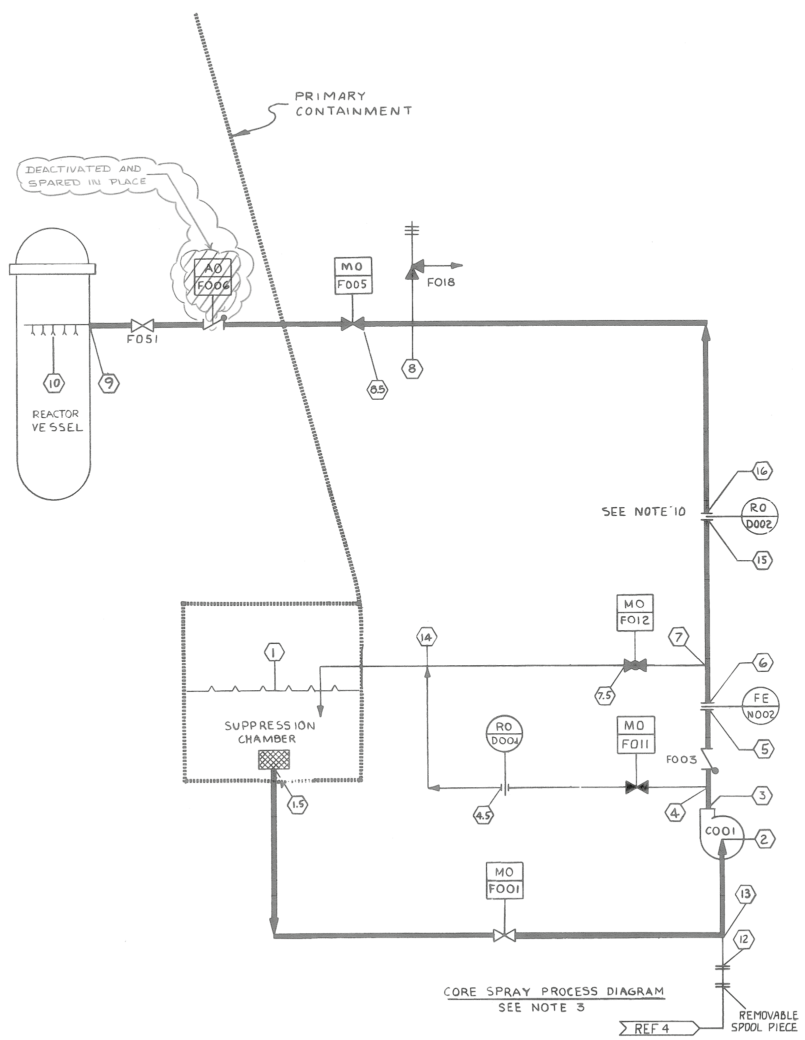
High–Pressure Core Spray and Low–Pressure Core Spray Flow Diagrams

Draw. No. M520	Rev. 103	Figure 6.3-4



Head Versus High-Pressure Core Spray Flow used in LOCA Analysis

Draw. No. 960222.12 | Rev. | Figure 6.3-5



CORE SPRAY PROCESS DIAGRAM
SEE NOTE 3

MODE A (NOTE 13) SYSTEM TEST, SUCTION FROM SUPPRESSION POOL

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10		12	13	14
FLOW - GPM	N/A	7800 ←					→ 7800	0	0	0		0	0	7800
PRESS - PSIA	14.7	X	X	X	X	X		X	X			X	X	
TEMP - °F	120/40	←					→ 120/40	AMB ←					→ AMB	120/40
MAX PRESS DROP - FT		• 500 •												

MODE B SYSTEM TEST, SUCTION FROM RESIDUAL HEAT REMOVAL SYSTEM

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10		12	13	14
FLOW - GPM	N/A	8200 ←								→ 8200		8200	8200	0
PRESS - PSIA	14.7		X	X	X	X	X	X	X	14.7				X
TEMP - °F	N/A	125/40 ←								→ 125/40		125/40	125/40	AMB
MAX PRESS DROP - FT		• 450 •												

MODE C PUMP OPERATING ON BYPASS, SUCTION FROM SUPPRESSION POOL

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10		12	13	14
FLOW - GPM	N/A	635	635	635	0	0	0	0	0	0		0	0	635
PRESS - PSIA	14.7	X	X		X	X	X	X	X	X		X	X	
TEMP - °F	212/40	←	→	212/40	AMB ←								→ AMB	212/40
MAX PRESS DROP - FT		1075/820												

MODE D ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY (128 PSID)

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW - GPM	N/A	6350 ←								→ 6350
PRESS - PSIA	14.7									142.7
TEMP - °F	170	←								→ 170
MAX PRESS DROP - FT		• 674 •				• 17 •			• 198 •	

MODE E ACCIDENT, SYSTEM INJECTION AT RATED CORE FLOOD

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW - GPM	N/A	7214 ←								→ 7214
PRESS - PSIA	14.7	X	X	X	X	X	X	X	X	40.7
TEMP - °F	170/40	←								→ 170/40
MAX PRESS DROP - FT		• 515 •								

MODE F ACCIDENT, SYSTEM OPERATING AT RUNOUT

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW - GPM	N/A	8100 ←								→ 8100
PRESS - PSIA	14.7		X	X	X	X	X	X	X	14.7
TEMP - °F	212	←								→ 212
MAX PRESS DROP - FT		• 500 •								

MODE S SYSTEM ON STANDBY DUTY

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW - GPM	N/A	0 ←												→ 0
PRESS - PSIA	14.7		X	X	X	X	X	X	X	REF 3	14.7	X	X	X
TEMP - °F	120/40	←					→ 120/40	AMB	AMB	AMB	120/40	←		→ 120/40
MAX PRESS DROP - FT		• 0 •												

FCF-239X287AD (E21-1020)

NOTES:

1. ALL EMPTY PRESSURE DATA BLANKS CAN BE FILLED IN BY OTHERS BASED ON ACTUAL ARRANGEMENTS OR EQUIVALENT HYDRAULIC DATA SUBMITTED TO APED FOR REVIEW. ⊠ INDICATES THE DATA IS NOT SIGNIFICANT.
2. ◿ INDICATES MAXIMUM & MINIMUM VALUE OF PARAMETER FOR THE MODE SPECIFIED.
3. ELEVATIONS ARE NOT INCLUDED IN THE ΔP VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
4. THE BY-PASS FLOW SPECIFIED IN MODE C IS APPROXIMATED AND WILL BE SPECIFIED BY THE PUMP VENDOR.
5. IN MODE F, THE NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE AT A REFERENCE LOCATION 2 FEET ABOVE THE PUMP MOUNTING FLANGE MUST EQUAL OR EXCEED 30 FT. THE NPSH AVAILABLE AT THE PUMP SUCTION NOZZLE MUST EQUAL THIS VALUE PLUS THE DIFFERENCE IN ELEVATION BETWEEN THE REFERENCE LOCATION AND THE CENTERLINE OF THE PUMP SUCTION NOZZLE.
6. IN MODE B, THE NPSH AVAILABLE MUST EQUAL THE VALUE SPECIFIED IN NOTE 5 PLUS 20 FT.
7. 100 GPM IS INCLUDED IN THE FLOW GIVEN FOR MODE D TO COMPENSATE FOR LEAKAGE IN THE REACTOR INTERNALS. (114 GPM IN MODE E).
8. IN MODE D, 128 IS THE DIFFERENTIAL PRESSURE BETWEEN THE REACTOR VESSEL AND THE SUPPRESSION POOL.
9. THE FLOW SPECIFIED FOR MODE F IS THE MAXIMUM ALLOWABLE.
10. THE ΔP BETWEEN LOCATION 15 AND 16 WILL BE DETERMINED IN PRE-OPERATIONAL TEST. THE ΔP WILL BE ADJUSTED TO MEET THE FLOW REQUIREMENTS OF MODE D, E OR F.
11.
12. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN TEMPERATURE AND PRESSURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DIAGRAM HYDRAULIC REQUIREMENT.

REFERENCE DOCUMENTS:	MPL ITEM NO.
1. LPCS SYSTEM P&ID	E21-1010
2. LPCS SYS. DESIGN SPEC.	E21-4010
3. NUCLEAR BOILER SYS. PROC. DIAG.	B22-1020
4. RESIDUAL HEAT REMOVAL SYSTEM P&ID	E12-1010

SUPPLEMENTAL DOCUMENTS:

1. PIPING & INSTRUMENT SYMBOLS	A42-1010

NOTES: (CONT'D)

13. TO ADDRESS MODE A, THE LPCS RECIRCULATION LINE AND ITS ORIFICE LPCS-RO-4 IS SIZED FOR THE PUMP RUN-OUT FLOW OF 7800 GPM (REF. CVI 215-04-51). DURING ACTUAL TESTING, VALVE LPCS-V-12 IS THROTTLED TO CONFIRM COMPLIANCE WITH THE TDH AND FLOW REQUIREMENTS OF TECH SPEC SR 3.5.1.4.

TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENTS
F	1.5-13-2	SEE NOTE 5
D OR E	3-4-5-6-15-16-8-8.5-9-10	
A	7-7.5-14	
C	4-4.5-14	
B	12-13	SEE NOTE 6

VALVE POSITIONS

CONDITION	VALVE NO. F001	F005	F012	F011
MODE A	O	C	P	C
MODE B	C	O	C	C
MODE C	O	C	C	O
MODE D	O	O	C	C
MODE E	O	O	C	C
MODE F	O	O	C	C
MODE S	O	C	C	C

P - PARTIALLY OPEN
C - FULLY CLOSED
O - FULLY OPEN

MISCELLANEOUS INFORMATION SEE NOTE 12

LOCATION ⬡	1.5	2	3 4 5 6 7 8	8.5	9	4	4.5	14	7	7.5	14	12	13
DESIGN TEMP (°F)	212	LPCS PUMP	← 212 → 488	SEE REF 3		← 212 →			← 212 →			← 212 →	
DESIGN PRESS (PSIG)	100		← 427 →	SEE REF 3		427	100		427	100		← 100 →	
ESTIMATED LINE SIZES (IN.)	18"		← 16" →	12"		← 4" →			← 12" →			← 16" →	
	MAIN CORE SPRAY LINE TO REACTOR					BYPASS LINE			TEST LINE			RHR SUCTION TEST LINE	

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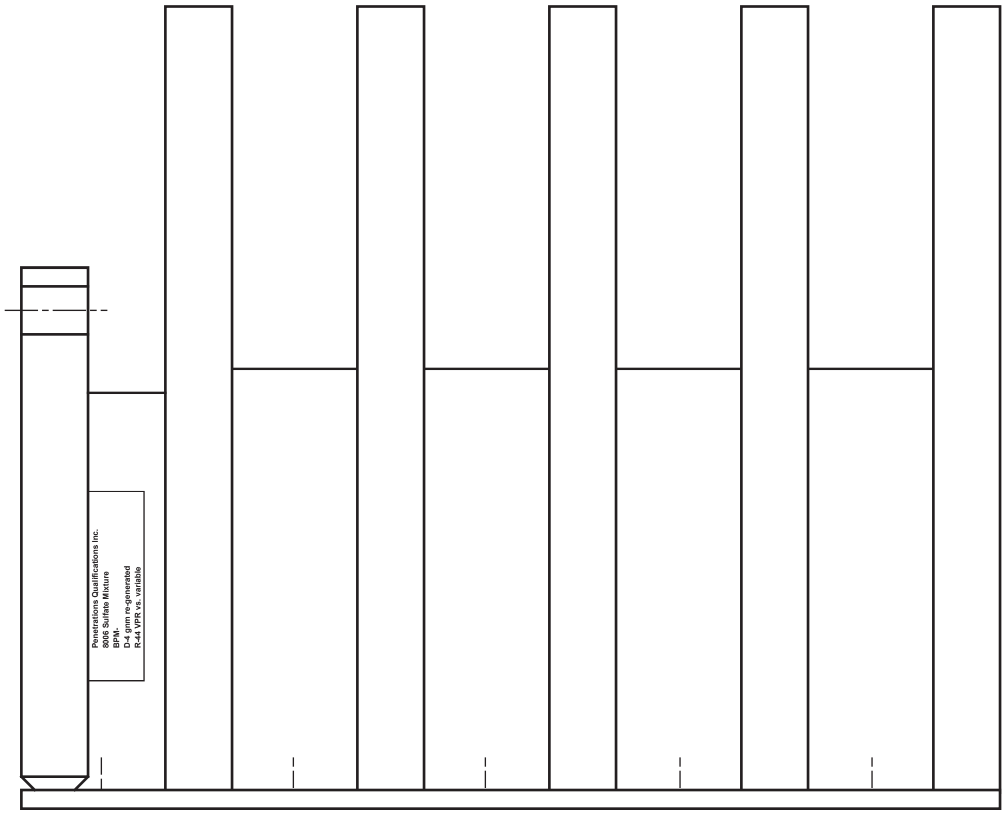
Low-Pressure Core Spray - Process Diagram

Draw. No. 02E21-04,4,1 Rev. 8 Figure 6.3-6

Form No. 960690ai

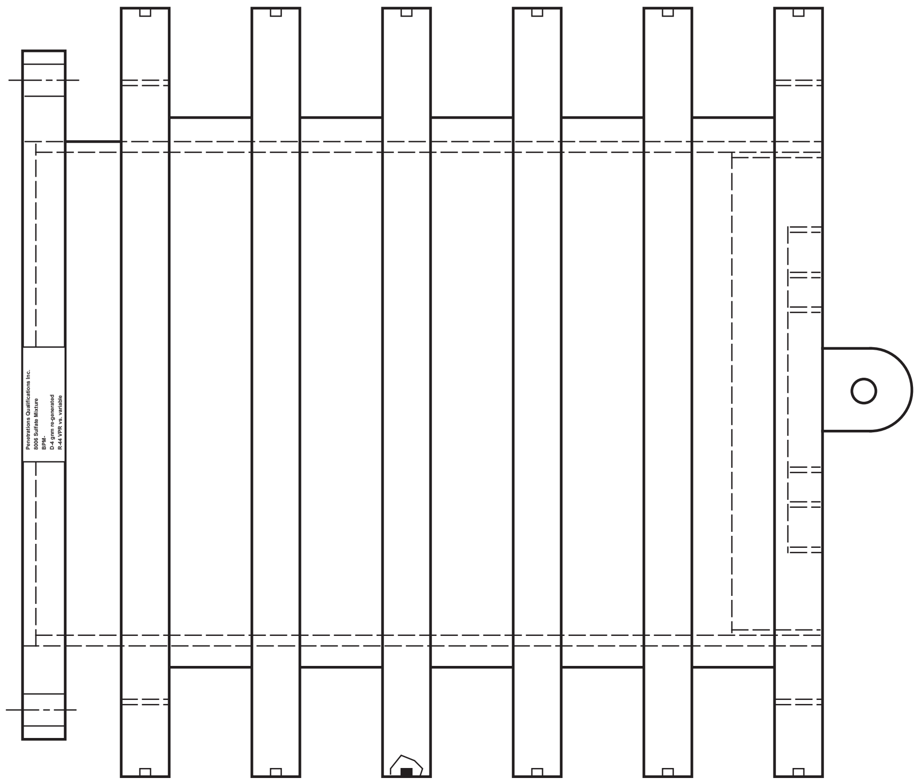
48 inch Diameter Half - Strainer Configuration
for Penetrations X-32, X-35



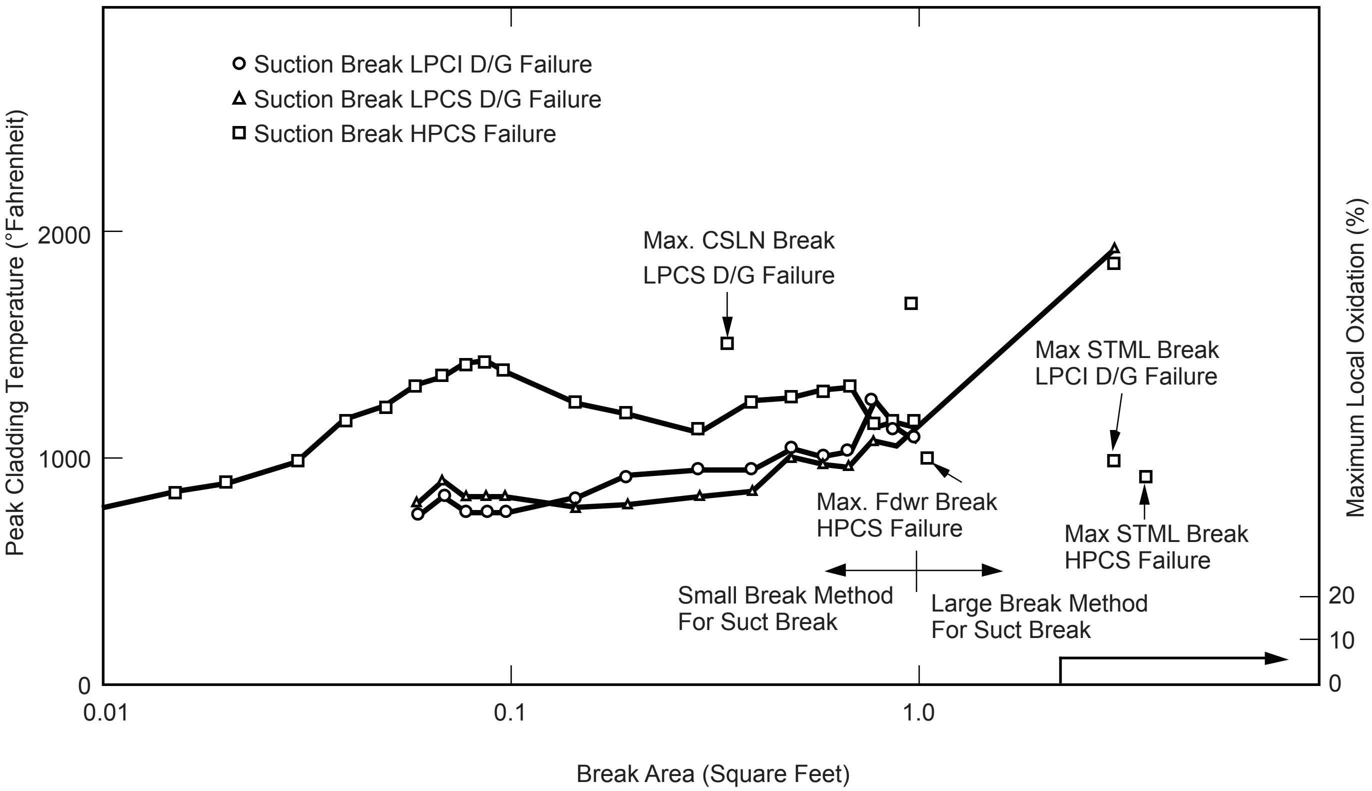
Note: Strainer halves are bolted together to form one strainer with a 47.5 inch Outer Diameter

Columbia Generating Station **Final Safety Analysis Report**	**Typical 48 in. Diameter Strainer**
	Draw. No. **920843.07** | Rev. | Figure **6.3-7**

36 inch Diameter Strainer Configuration
for Penetrations X-31, X-34, and X-36



Note: The number of disks varies with strainer length.



Peak Cladding Temperature and Maximum Local Oxidation Versus Break Area - Hanford Original Rated Power

Draw. No. 960222.23 | Rev. | Figure 6.3-9

6.4 HABITABILITY SYSTEMS

6.4.1 DESIGN BASIS

The main Control Room Envelope Habitability (CREH) systems are designed to ensure habitability inside the main control room. The CREH systems ensure the Control Room Envelope (CRE) occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, a hazardous chemical release, or a smoke challenge. The CREH systems ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions. Under DBA conditions, personnel will receive radiation exposures no greater than 5 rem total effective dose equivalent (TEDE) for the duration of the accident in accordance with 10 CFR part 50.67 as discussed in Chapter 15. The CREH Program ensures the CREH system is in compliance with General Design Criterion 19 (GDC 19) of 10 CFR 50, Appendix A, and in compliance with the guidance of Regulatory Guide 1.196.

Emergency supplies for the control room, technical support center (TSC), and operational support center will be provided by the Emergency Response Organization. Portable breathing apparatus is also provided in the control room for operating personnel protection in the event of a fire external to the plant or a chemical spill on or offsite. The control room heating, ventilating, and air conditioning (HVAC) is operated in the recirculation mode without filtration by the emergency filter units for both of these scenarios.

In the event of a LOCA, operating personnel within the control room are protected from airborne radioactivity for up to 30 days by means of pressurizing the control room with filtered air drawn from two separate remote fresh air intakes through the control room emergency filtration (CREF) system. Both intakes are physically remote from all plant structures. The CREF system has two redundant trains which can filter air drawn for the intakes. The system is designed such that both trains will start simultaneously, however a single train operation results in higher LOCA dose than a dual train operation, therefore the license basis LOCA dose analysis assumes a single train operation. If two trains start, the operator will be directed to not stop the second train until at least 10 hours post accident.

Adequate shielding is also provided to protect operating personnel from radiation streaming. The control room doors are adequately designed to protect operating personnel from a steam pipe break in the turbine generator building.

The control room HVAC is also pressurized in the event of a fire within the plant, but external to the control room, to prevent ingress of smoke or combustion vapors.

Components of the HVAC systems serving the control room that are required to ensure control room habitability and essential equipment operations are redundant, Seismic Category I, and powered from Class 1E buses.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Main Control Room Envelope

The main control room is located on el. 501 ft of the radwaste building. Included in the CRE are all essential control equipment of the plant plus a toilet, kitchen, dining area, and an office area. These areas are frequently occupied.

The CRE boundary is the combination of walls, floor, ceiling, doors, penetrations, ducting, and equipment that physically form the boundary of the CRE. The equipment boundary includes fan housings, air handlers, and associated drain loop seals of the control room ventilation systems. The ducting boundary includes the HVAC ducts serving the control room starting from the fresh air isolation dampers to the common supply header penetrating the control room ceiling, and up to the isolation damper in the kitchen and bathroom exhaust duct. The enclosed volume of the CRE is approximately 214,000 ft^3. See Reference 6.4-1 for a more detailed description of the CRE.

6.4.2.2 Ventilation System Design

A description of the ventilation systems serving the control room and a listing of the design and performance parameters of the ventilation system equipment is provided in Section 9.4.1.

6.4.2.3 Leaktightness

A description of system leaktightness is discussed in Section 9.4.1.

6.4.2.4 Interaction With Other Zones and Pressure Containing Equipment

Normal access into the main control room is through corridors that are radiologically clean. Chemicals stored within the radwaste building or the immediately adjacent structures are in small quantities and are not hazardous to control room personnel.

Within the main CRE, there are no pressure vessels or piping systems that would affect control room habitability, except for the individual Halon fire extinguishing system within the control panels. Halon emitted to the main control room would be in the form of leakage from the Halon flooding systems. If all the Halon cylinders in the largest system were to release

simultaneously, the projected concentration in the CRE would be about 2690 ppm (<0.3% by volume). This concentration is significantly less than the 50,000 ppm level at which the concentration would be immediately dangerous to life and health (IDLH). The decrease in oxygen concentration in the control room would be approximately 0.1%. The main control room is protected from external pressurized systems by distance and concrete shield walls.

6.4.2.5 Shielding Design

The control room is designed with adequate shielding to protect occupants from conditions of airborne activity in containment and the reactor building, airborne activity in the radwaste building, the activity surrounding the building as a result of isotopes released to the environment, and activity built up on the main control room filters (located one floor above the control room). The concrete walls surrounding the control room are a minimum 2 ft thick and the floor and ceiling slabs are a minimum 1 ft thick. Radiation streaming is minimized by locating equipment, cable tray, and duct penetrations in the areas where radioactive sources are weak or nonexistent. There are no significant piping penetrations into the main control room. The normal primary access doors have been designed with air locks and may be used to prevent air inleakage into the control room during ingress and egress. The control room dose analysis for a LOCA does not take credit for the installed control room door air locks to minimize air inleakage. Radiation streaming through the doors has also been analyzed and evaluated as insignificant.

Direct doses to the control room from confined sources such as in some areas of the radwaste building, the turbine building, and from potential DBA sources in containment and in the reactor building are negligible due to local shielding provided around the source and shielding around the control room. Radiation from containment must penetrate the following shielding before reaching the control room: the 0.75-in. steel containment shell, the 5-ft-thick concrete biological shield wall, the 2-ft-thick concrete reactor building wall, and the 2-ft-thick concrete control room wall. Similarly, a 2-ft-thick concrete wall exists between the turbine building and the 2-ft-thick control room wall. In areas, the turbine building wall is 42 in. thick for shielding and missile purposes yielding 5.5 ft of protection to the control room from turbine building radiation areas. The HVAC room above the control room has an 18-in. concrete roof slab. This room coupled with the 1-ft-thick concrete control room ceiling yields an effective 2.5 ft of concrete shielding for the control room ceiling.

Details of the dose evaluation for the control room are given in Chapter 15.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

During normal and emergency operation the control room operator selects the air handling unit which operates to maintain design temperatures in the control room. Periodically the operating unit is exchanged with the standby unit so that the service time of both units is approximately

equal. In the event the operating unit fails, control room personnel start the standby unit from the control room.

The responses of the control room habitability system to either hazardous chemical or airborne radioactivity are compatible. In the event of a hazardous chemical release, the operators may take action to stop the exhaust fan, shut the associated damper, and close the fresh air inlet damper for each HVAC train. In the event of a hazardous radioactivity release, the operators may respond by closing the appropriate remote intake isolation valves. Portable breathing apparatus is available.

6.4.4 DESIGN EVALUATION

6.4.4.1 Radiological Protection

Personnel in the main control room are protected from the radiological effects of a postulated accident by pressurizing the main control room with 1000 cfm of filtered air drawn from either of two remote fresh air intakes. This operation limits the 30-day dose to operators to below that of GDC 19 of 10 CFR 50, Appendix A, and 10 CFR 50.67. Essential components of the control room habitability systems are redundant, Seismic Category I, and powered from Class 1E buses.

The emergency ventilation system is of the dual inlet design with manual isolation valves above the control room. See Section 9.4.1 for the system description. The guidance in Regulatory Guide 1.183 was used in the control room dose analyses for Columbia Generating Station (CGS) and is addressed in the individual event evaluations in Chapter 15.

6.4.4.2 Toxic Gas Protection

6.4.4.2.1 Chlorine

Chlorine is not used at CGS. Transportation routes involved in chlorine movements include Hanford Route 4 South to the west on which there may be four shipments per year. In the past, 1-ton cylinders have been shipped two or three times per year on the Hanford Railroad (750 ft east of CGS); however there have been none since June 1983 and it is anticipated that chlorine will continue to be transported on the highway instead.

Control room concentrations from a postulated accident were calculated using the methodology of References 6.4-2 and 6.4-3. Assuming no operator action, the maximum control room concentration of gaseous chlorine from an offsite accident involving the rupture of a 1-ton cylinder at a point 4500 ft directly upwind of the control room air intake is 29 mg/m^3 at 32 minutes after the arrival of the leading edge of the initial vapor cloud. This is below the 45 mg/m^3 2-minute toxicity limit specified in Reference 6.4-4.

The protection provided to the control room operators from an offsite chlorine release includes the capability of closing the control room air ducts with dampers and isolating the control room. The postulated accident and associated assumptions would yield concentrations exceeding the short-term exposure limit of 11.5 mg/m^3 specified by Reference 6.4-5 for approximately 3.5 hr assuming no operator action. Since the odor threshold is approximately 0.01 ppm (0.03 mg/m^3), per Reference 6.4-6, operators could quickly detect the presence of chlorine and isolate the control room. With this realistic assumption, there would be no hazardous exposure to chlorine.

In summary,

a. The CGS control room fresh air intake is not equipped with chlorine detectors and automatic isolation equipment,

b. No chlorine is stored onsite, and

c. Chlorine storage and movement within 5 miles is less than thresholds specified in Reference 6.4-4.

6.4.4.2.2 Sodium Oxide

The Department of Energy Fast Flux Test Facility (FFTF) is located approximately 4000 m southwest of CGS. A large quantity of liquid sodium was used in the operation of the FFTF. The facility is shut down and in the process of deactivation and decommissioning. Sodium has been drained from the primary and secondary heat transfer system loops and is being maintained in solid state in the Sodium Storage Facility tanks. A small amount of residual sodium remains in the piping systems and has been solidified (Reference 6.4-7).

The accident evaluated during the initial licensing of CGS was a liquid sodium release from a FFTF secondary loop component failure due to a tornado. The probability of such a release is significantly reduced because the primary and secondary loops are now drained and the sodium solidified. Since solidified sodium continues to be located at the site, this analysis is retained as a bounding event until the solidified sodium is removed from the site or the possibility of a release is further reduced.

The analysis is assumed that a failure occurs in the FFTF secondary loop component due to a tornado. A resulting postulated 100,000-lb sodium release over 20 hr was considered bounding for CGS control room habitability purposes (Reference 6.4-8).

The following assumptions are made:

a. Two million pounds of liquid sodium contained in the primary coolant loop are not considered in the analysis since it is contained in the FFTF reactor containment building,

b. 100,000 lb of liquid secondary sodium may be released and ignited,

c. Up to 36% of the sodium oxide formed in the combustion of the 100,000 lb of sodium may be released and transported away as an aerosol,

d. Fire resulting from the accidental release of 100,000 lb of sodium would consume the available sodium at whatever rate it is released, and

e. The average sodium oxide release rate assumed was for a 20-hr postulated incident at 2426.4 lb/hr.

Where applicable, Reference 6.4-4 was utilized. However, due to the nature of the postulated sodium fire and the complexities of the dispersion analysis, the following additional modeling assumptions were utilized:

a. CGS onsite meteorological data collected from April 1974 through March 1976 was used to establish the upper wind speed values in addition to the established 5% dispersion meteorology for the CGS site;

b. To account for the rise of sodium oxide aerosol due to the buoyancy of the hot gases, the height of rise of the aerosol plume was conservatively predicted using Part 1, References 6.4-9 and 6.4-10;

c. To account for settling and deposition of the sodium oxide particulates within the plume, depleted source terms were established (Reference 6.4-11); and

d. Six plume dispersion modeling equations were used to calculate concentrations outside the CGS control room fresh air intakes as a function of wind speed and stability. Credit for FFTF building wake dilution effects during high wind speed conditions, plume meandering for stable low wind speed conditions, and both a depleted plume equation and tilted plume equation to account for deposition were included as discussed in References 6.4-11, 6.4-12, and 6.4-13.

The analysis resulted in a maximum sodium oxide concentration outside the control room intakes of 8.7 mg/m^3. A wind speed of 1.2 m/sec would allow FFTF approximately 55 minutes to warn CGS control room personnel of the approaching sodium oxide cloud, assuming that the cloud was traveling directly toward the CGS site. The permissible warning

time, as well as the cloud concentration, would increase for lighter wind speed conditions, i.e., up to approximately 1.5-hr warning time for a 0.75 m/sec wind producing a maximum cloud concentration of 8.7 mg/m^3. Wind speeds greater than 1.2 m/sec yield concentrations less than the long-term toxicity limit of 2 mg/m^3.

A warning time of approximately 55 minutes is sufficient to permit proper notification to take place between FFTF and Energy Northwest personnel, to isolate the CGS control room. Procedural arrangements are in place between FFTF and Energy Northwest for timely notification of the control room in the event of a sodium oxide release. In the unlikely event that sodium oxide enters the control room, portable breathing equipment is available.

6.4.4.2.3 Miscellaneous Chemicals

Other onsite stored chemicals were reviewed in accordance with Reference 6.4-4 to assess their potential impact on the habitability of the control room in the event of postulated hazardous chemical releases. Chemicals stored onsite and analyzed for impact on the control room habitability are ammonium hydroxide, carbon dioxide, trichlorofluoromethane (Freon-11), dichlorodifloromethane (Freon-12), chlorodifluoromethane (Freon-22), trichlorotrifluoromethane (Freon-113), and 1,1,1,2-tetrafluoromethane (Freon-134a), hydrogen peroxide, hydrogen, isopropyl alcohol, methyl ethyl ketone, nitrogen (liquid), propane, sodium hydroxide (in solution), sodium hypochlorite, sodium bromide, and sulfuric acid, diesel fuel, ethylene glycol, fyrquel, GE Betz Dearborn inhibitor AZ8104, gasoline, Halon 1301, hydrochloric acid, mineral spirits, insecticide, herbicides, fertilizers, lubricants, transformer oils, ONDEO NALCO chemicals, paint products, propylene glycol, and polyaluminum chloride solution.

The analysis (Reference 6.4-14) indicated that most of these chemicals did not require chemical hazard evaluations due to the fact that they exist in small quantities, are stored far away from the control room intakes, have a very low vapor pressure, or are bounded by the results of the calculations performed on the chemicals listed below.

The following chemicals met the screening criteria of Reference 6.4-4 required a chemical hazard evaluation:

a. A liquid nitrogen storage tank containing 75,000 lb of nitrogen located at the corner of the diesel generator building.

b. A tank containing 12,000 lb of cardox (CO2) stored in the turbine generator building.

c. A 55-gallon drum containing ammonium hydroxide stored approximately 100 ft from building 74 (warehouse for maintenance lubricants).

d. Two tanks containing 1700 gallons each of Freon-11 stored in the Refrigerant Storage and Maintenance building (Building 72) approximately 800 ft from the nearest control room air intake.

Postulated releases to the atmosphere and subsequent transport to control room fresh air intakes of these chemicals were evaluated. The results of the analysis (Reference 6.4-14) indicated that an accidental release of these chemicals will result in concentrations in the control room that are well below the toxicity limit of each of the chemicals. Therefore, these chemicals do not pose a hazard to the control room operators.

There are a significant number of compressed gas bottles containing process gasses such as nitrogen, hydrogen, argon, helium and others containing acetylene, argon/methane and oxygen used within the plant buildings and onsite bottle storage locations. These gas bottles do not represent a control room habitability concern due to the small quantity of gas contained in each bottle.

Maximum quantities of hydrogen gas stored in the gas bottle storage building (120 bottles containing a total of 144 lb) and in a trailer parked adjacent to the gas bottle storage building containing 294 lb will not pose any problem because the lightness and dispersal qualities of the gas and the distances (approximately 400 ft) to the nearest control room air intake would result in negligible concentrations at that location.

The Hydrogen Storage and Supply Facility (HSSF) has a maximum storage capacity of approximately 9800 pounds of liquid and gaseous hydrogen. The storage of this amount of hydrogen at the HSSF is not considered a hazard for control room habitability due to the distance (approximately 2900 ft) between the closest fresh air intake and the HSSF.

An 18,000-gal sulfuric acid storage tank, one 5000-gal tank of sodium hypochlorite, and one 5000-gal tank of sodium bromide are located near the circulating water pump house approximately 570 ft from the control room intake. Two 2100-gal tanks of hydrogen peroxide are located near pump house 1B (approximately 300 ft from the control room intake). Other stored chemicals include 500-gal propane tanks (located over 1100 ft from the control room intake), as well as other miscellaneous or transient storage of lesser quantities of chemicals that are bounded by the analyses performed for the chemicals stored in bulk quantities.

6.4.5 TESTING AND INSPECTION

The main control room HVAC system and its components are tested as follows:

a. Predelivery and component qualification tests,
b. Postdelivery acceptance tests, and
c. Postoperation surveillance tests.

Written test procedures establish acceptable criteria for the tests. The tests are performed to meet the objectives of Regulatory Guide 1.52 and Regulatory Guide 1.197.

The factory and component qualification tests consist of the following:

a. All equipment was factory inspected and tested in accordance with the applicable equipment specifications, codes, and quality assurance requirements. System ductwork and erection of equipment was inspected during various construction stages for quality assurance. Construction tests were performed on all mechanical components and the system was balanced for the design air and water flows and system operating pressures. Controls, interlocks, and safety devices were checked, adjusted, and tested to ensure the proper sequence of operation.

b. The emergency filter units, which are normally in standby, are started periodically to ensure fan operation. The fans are factory tested in accordance with AMCA Standard 210, "Air Moving and Conditioning Association, Test Code for Air Moving Devices."

   Filters are tested as described in Section 9.4.1.

c. All valves associated with the control room HVAC system are factory leak tested, bubble tight, at a pressure differential of 0.2 psig. Electrically operated valves are factory tested to ensure that valve stroke time, full open to full close, does not exceed 4 sec. Once installed, the valves are stroked to verify operability. The fresh-air intake valves are periodically tested to ensure control room inleakage through closed intake valves is minimized.

d. The postdelivery acceptance tests are performed as described in Section 14.2.

e. The operational surveillance testing is described in the Technical Specifications.

6.4.6 INSTRUMENTATION REQUIREMENTS

A discussion of instrumentation associated with main control room habitability systems is provided in Sections 9.4.1 and 7.3.1.1.7.

6.4.7 REFERENCES

6.4-1 "Control Room Boundary Leakage Limitations," TM-2082, Revision 5.

6.4-2 Turner, D. B., Workbook of Atmospheric Dispersion Estimates, Public Health Service, U.S. Department of Health Education, and Welfare, Figures 3.2 and 3.3, 1970.

6.4-3 Wing, J., Toxic Vapor Concentration in the Control Room Following a Postulated Accidental Release, NUREG-0570, Nuclear Regulatory Commission, June 1979.

6.4-4 "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," Regulatory Guide 1.78, June 1974.

6.4-5 Nuclear Regulatory Commission, Standard Review Plan, Section 6.4, NUREG-0800 (Revision 2), July 1981.

6.4-6 Occupational Health Guidelines for Chemical Hazards, NIOSH, U.S. Department of Health and Human Services, August 1981.

6.4-7 FFTF Hazard Analysis Supporting Discussion & Analysis, "Fast Flux Test Facility Hazard Assessment," HNF-SD-PRP-HA-0.15 Revision 6, April 31, 2007.

6.4-8 Excerpts from Sections 6.4, "Habitability System," and 15.2, "Accident Analyses," of the FFTF FSAR (Amendment 3, February 1, 1977).

6.4-9 Briggs, G. A., "Plume Rise: A Recent Critical Review," Nuclear Safety Vol. 12, No. 1, 1971.

6.4-10 Briggs, G. A., "Plume Rise Predictions," Lectures on Air Pollution and Environmental Impact Analysis, American Meteorological Society, Boston, Mass., 1975.

6.4-11 Slade, D., Meteorology and Atomic Energy, U.S. Atomic Energy Commission, Division of Technical Information, Springfield, VA 1968.

6.4-12 Stern, A. C., Air Pollution, Their Transformation and Transport, Vol. I Third Edition, Academic Press, New York, 1976.

6.4-13 Nuclear Regulatory Commission, BTP HMB, Diffusion Conditions for Design Basis Accident Evaluations, 1977.

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6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURE FILTER SYSTEMS

There are two air filtration systems that are required to perform safety-related functions following a design basis accident. They are the control room emergency filtration (CREF) system, which is described in Sections 6.4 and 9.4.1, and the standby gas treatment (SGT) system described in this section.

6.5.1.1 Design Bases

The SGT system is designed to maintain airborne radioactive release from the secondary containment to the atmosphere within the limits required by 10 CFR 50.67. The system is designed to enable purging of the primary containment through the SGT system filters when airborne radiation levels inside the primary containment are too high to permit direct purging to atmosphere by means of the reactor building exhaust system as discussed in Section 9.4.

The SGT system design meets seismic requirements and single failure criterion. Each SGT system filter train is sized to maintain the secondary containment (reactor building) at least 0.25-in. water gauge below atmospheric pressure under the following conditions:

a. Air leakage into the secondary containment at a continuous rate of one building air change per day,

b. A drop in barometric pressure at the rate corresponding to adverse meteorological conditions,

c. Relative humidity increase resulting from vapor from the spent fuel pool, and

d. The volumetric expansion of air within the secondary containment due to the heat sources in the reactor building.

6.5.1.2 System Design

The SGT system is shown in Figure 3.2-2. The layout of the SGT system units is shown in Figure 12.3-23. Principal system components are listed and described in Table 6.5-1. The system consists of two fully redundant filter trains, each of which consists of the following components in series:

a. A demister (moisture separator) to remove entrained water particles in the incoming air stream;

b. Two banks of electric blast coil heaters, one primary and one backup, each powered from separate emergency diesel buses. Each heater is composed of three 6.9 kW stages and is sized to limit the relative humidity of the heated air to 70% at design flow during post-LOCA conditions;

c. A bank of prefilters to remove most particulates from the air stream. The filters have an atmospheric dust spot efficiency of 80-85% by ASHRAE Standard 52.1 (MERV 13 rating by ASHRAE standard 52.2);

d. A bank of high-efficiency particulate air (HEPA) filters to remove virtually all particulates, including iodine fission products from the airstream;

e. Two 4-in.-deep bank of charcoal adsorber filters are installed in series. Filters are of an all-welded, gasketless design. Each charcoal adsorber filter has electric strip heaters.

f. A second bank of HEPA filters, identical to item d. The function of this second HEPA filter bank is to capture charcoal dust as well as particulate fission product releases that may escape from the charcoal filters.

All of the above components are mounted in an all welded steel housing. The SGT filter trains are located on the el. 572 ft of the reactor building. A 12-in.-thick concrete partition wall, 14 ft high, separates the two trains. The Seismic Category I design partition wall serves as both a missile barrier and fire barrier between the two trains.

There are at least 2268 lb of charcoal in each of the two adsorber units. The adsorbing capability of each unit is 2.5 mg of halogens per gram of charcoal or a total of 2577 g. The maximum theoretical accumulation of halogens on the SGT system adsorbers for a 30-day period after a LOCA is 67 g.

Three independent deluge spray systems are provided for fire protection in each SGT filter train. One deluge spray system is provided for protection of the prefilter and a deluge spray system is provided for each of the two charcoal filter beds.

Two centrifugal fans are provided with each SGT filter train. The primary fan starts automatically upon receipt of an initiation signal. The backup fan operates only in the event of primary fan failure. The two fans of each unit are powered from separate emergency diesel buses. Two identical control systems which are supported by emergency power adjust the automatic inlet vanes on the fans to control flow rate. See Section 7.3.1.1.9. Ductwork and butterfly valves on the discharge air side of each filter train are arranged such that either fan can draw air through the filter train and discharge it either out of the reactor building, by means of the reactor building elevated release duct, or back into the reactor building.

Provision is made to return air to the reactor building so that decay heat generated within the SGT unit due to the collection of radioactive contaminants is removed.

Ductwork and valving for the intake of each SGT unit is configured so that the units can draw air from the reactor building in the immediate vicinity of the unit, the primary containment drywell, the wetwell, or from any combination of the three locations. The connection to primary containment is through the primary containment purge exhaust lines.

During normal plant operation both SGT units are on standby. In standby, only the strip heaters in the charcoal sections operate. The strip heaters cycle to maintain the filter plenum temperature to ensure that the relative humidity within the plenum does not exceed 70%. This protects the charcoal adsorber from condensed moisture.

The maximum dewpoint temperature in the reactor building during normal plant operation is 75°F. When in standby, all isolation valves downstream of the unit fans are closed. Whenever the drywell requires venting to relieve pressure, purging to inert or to deinert, or purging to improve the quality of the drywell atmosphere, the SGT system can be used to treat the effluent gas before release. For this process, the system is manually operated from the control room. The operator initiates the SGT system and adjusts SGT flow to the required flow rate. A sensor in the fan discharge duct transmits a flow signal to a recorder monitored by the operator during the evolution. Purge supply air to the primary containment is supplied from the reactor building supply air system. During the process of inerting, nitrogen gas is supplied from the containment nitrogen inerting system.

Both SGT filter trains are automatically actuated by the following signals:

a. High radiation in the reactor building ventilation exhaust duct,
b. High pressure in the drywell, and
c. Reactor vessel low-low water level.

When actuated the following sequence of events occur in each SGT train:

a. The primary bank of electric blast coil heaters is energized and all valves begin to move to their proper positions;

b. After the primary bank of heaters has time to reach a temperature that will ensure air entering the charcoal bed is maintained below 70% relative humidity, the primary fan receives a start signal;

c. If the primary fan fails to start or run, following a time delay, the primary fan and heater are deenergized. Then the primary fan inlet valve receives a close signal and the backup heater is energized. Next, following an additional time

delay to reach temperature, the backup fan isolation valve is opened and the backup fan receives a start signal;

d. The operating fan inlet vane position is controlled by the reactor building pressure control system to ensure that secondary containment pressure is reduced to at least a negative pressure of 0.25 in. w.g.. The control system will adjust fan flow rate as needed to maintain the negative pressure.

Both SGT units are operating within two minutes following the initiation signal. The same sequence is followed if the initiation signal is coincident with a loss of offsite power.

The operator may stop one of the SGT trains from the control room after startup is complete. In the event that the radiation monitors in the discharge duct indicate an unacceptable radiation level in the system discharge air, the operator starts the second unit and diverts the discharge air of the operating unit back into the reactor building to minimize offsite release of halogens and to cool the charcoal bed.

The following is a comparison of the engineered safety feature (ESF) filtration systems with each position detailed in Regulatory Guide 1.52, Revision 2, and Revision 3 as applicable.

Article A - Introduction

The ESF filtration systems provided for CGS are designed to the General Design Criterion referenced in Article A. Those systems designed to meet the criterion are:

a. Standby gas treatment system, and
b. Control room emergency filtration system.

Article B - Discussion

The two systems are both classed as secondary systems and are not subject to the drywell environment during any design basis accident and are not subject to containment cooling sprays. Equipment design includes the ability to operate under all environmental conditions to which they can be subjected during accident conditions. The components of each control room filter unit are as described in this article except that no demisters are required and HEPA filters are not provided downstream of the charcoal adsorber section. The effects of aging, weathering, and relative humidity have been considered in the design of these atmosphere cleanup systems, and they are tested periodically to verify required performance capability.

The effects of moisture on the charcoal adsorber media is minimized by the use of strip heaters for humidity control in the plenum of the charcoal adsorbers section of the SGT system units and by periodically circulating heated air through the control room emergency filtration units. Adequate space and accessibility for personnel has been incorporated in filter unit design to

ensure maintainability and testability. Testing of filters is performed as specified in the Technical Specifications.

Article C - Regulatory Position

Section 1.8.3 provides an analysis of the engineered safety feature air filtration systems with respect to the regulatory positions of Regulatory Guide 1.52, Revision 2.

Section 1.8.3 provides an analysis of required monthly run time to justify operability of the system and all components with respect to Regulatory Position 6.1 of Regulatory Guide 1.52, Revision 3.

6.5.1.3 Design Evaluation

The SGT system is designed to prevent the exfiltration of contaminated air from the secondary containment following an accident or abnormal occurrence. All necessary equipment and surrounding structures are Seismic Category I. The ESF buses supply power to the SGT system in the event of loss of normal ac power. Two fully redundant equipment trains separated by a missile wall are provided to ensure that a single failure does not impair or preclude system operation.

6.5.1.4 Tests and Inspections

The SGT system and its components are thoroughly tested in a program consisting of the following classifications:

a. Predelivery tests and component qualification tests,
b. Postdelivery acceptance tests, and
c. Postoperation surveillance tests.

All SGT system fans were factory tested in accordance with AMCA Standard 210, "Air Moving and Conditioning Association Test Code for Air Moving Devices." Fans are started once per month to ensure operability.

Written test procedures establish acceptance criteria for all tests. Test results are recorded in performance records.

Predelivery tests were performed to meet the objectives of Regulatory Guide 1.52, Revision 2. Postdelivery tests were performed to meet the objectives of Regulatory Guide 1.52, Revision 2 (using ANSI N510-1980). Postoperation tests are performed as specified in the Technical Specifications.

The HEPA filters are factory tested to a minimum efficiency of 99.97% when measured with a 0.3-micron dioctyl phthalate (DOP) aerosol. Tests are performed in accordance with

ASME AG-1-1997. See Section 1.8.3 for compliance by alternate approach to Regulatory Guide 1.52, Revision 2. In place leak testing of the HEPA filters is conducted in accordance with Regulatory Guide 1.52, Revision 2, as discussed in Section 1.8.3, to demonstrate a penetration and system bypass of less than 0.05%.

Charcoal media qualification tests meet the objectives of Regulatory Guide 1.52, Revision 2.

Charcoal samples laboratory test results are required within 31 days of removal.

Charcoal beds are leak tested in accordance with the Technical Specifications to demonstrate a penetration and system bypass of less than 0.05%.

Valves associated with the SGT system were factory leak tested, bubble tight, at a pressure differential of 2 psig. Valves were factory tested to ensure that valve stroke time, full close to full open, did not exceed 4 sec. The SGT system valves are periodically stroked as specified in the Technical Specifications to ensure operability.

6.5.1.5 Instrumentation Requirements

Additional information regarding the instrumentation and control system for SGT is contained in Section 7.3.1.

The instrumentation and controls are designed to meet the objectives of Regulatory Guide 1.52, Revision 2.

The following instrumentation is provided for each SGT train in addition to that previously described:

a. An indicating differential pressure gauge is provided across each element (excluding heaters) in the SGT train. High differential pressure alarms in the main control room and is recorded by computer;

b. Relative humidity detectors with humidity indication in the main control room are located before the electric blast coil heaters and the charcoal adsorber banks. High humidity alarms in the main control room and is recorded by computer;

c. Thermostats with sensors on either side of an adsorber section control strip heaters in both adsorber plenum sections. Two thermostats in parallel energize the heaters on a temperature drop to 90°F. Another thermostat deenergizes the heaters on a temperature rise to 110°F, with a manual reset thermostat cutting out the heaters on a temperature rise to 125°F; and

d. Temperature indication is provided in the main control room for air entering the electric blast coil heater section and the air leaving both banks of charcoal

filters. Temperature switch sensors are located on the downstream side of the prefilter and adsorber sections. A temperature rise to 250°F causes an alarm in the main control room. The control room operator determines the cause of the temperature rise and can manually initiate the deluge spray system if necessary.

6.5.1.6 Materials

The housings and framing materials of the SGT filter units are fabricated of steel alloys and, as such, are nonflammable. The following is a list of the materials used in the various components of the SGT filter units.

Demisters - The demister (moisture separator) section of each SGT unit consists of four assemblies of metal baffle plates and fiberglass separator pads. Each assembly has three fiberglass pads and one 4-in.-thick galvanized metal moisture eliminator with a nominal face area of 16 x 20 in.

Prefilters - There are four 24 in. x 24 in. prefilters in each SGT unit. The prefilters are a pleated, U.L. Class 1, fiberglass mounted on a metal retainer frame.

Absolute Particulate Filters - There are two banks of HEPA filters, one before and one after the charcoal adsorber section, on each SGT filter unit. The HEPA filters consist of U.L. Class 1 fiberglass media in stainless steel frames with aluminum separators. There are four 24 in. x 24 in. filters in each filter bank.

Charcoal Adsorber Media - Each charcoal adsorber filter unit (two per SGT train) contains about 40 ft^3 of charcoal. The charcoal used in the filters is a potassium iodide or triethylenediamine (TEDA) impregnated coconut base charcoal. Typically, over 1000 lbs of charcoal are contained in each of the four filter units.

The only material in the SGT units that supports combustion is the charcoal, which has a minimum ignition temperature of 330°C. The charcoal is provided with a deluge spray system. A 12-in.-thick concrete partition wall is provided between the two SGT units for fire protection.

6.5.2 CONTAINMENT SPRAY SYSTEM

Design Bases

The containment spray system is capable of reducing containment pressure during the postaccident period of a LOCA through condensation of steam in the drywell and through cooling of the noncondensable gases in the free volume above the suppression pool. Containment spray is not required to prevent overpressurization of the containment.

The containment spray system also provides for fission product removal from the containment atmosphere. During a LOCA a substantial fraction of the fission product release occurs after initial blowdown is complete. No credit is taken for suppression pool scrubbing of the wetwell air space. A portion of the fission products released from the reactor pressure vessel will be removed from the drywell atmosphere by drywell sprays. The drywell sprays are assumed to be initiated 15 minutes after the LOCA and turned off after one day.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

The release of fission products to the environment in the event of a LOCA is controlled passively by the leaktight integrity of the primary and secondary containments and actively by the SGT system that filters the effluent from the secondary containment.

6.5.3.1 Primary Containment

Primary containment response to a design basis accident is discussed in Section 6.2.1. Figure 6.2-23 provides a basic layout of the primary containment.

In the event of a LOCA, oxygen concentration is controlled by the containment atmosphere control system which mixes, monitors, and controls the containment atmosphere as described in Section 6.2.5. Primary containment purging is discussed in Section 6.2.1.

6.5.3.2 Secondary Containment

The SGT system is provided to control the release of fission products from the secondary containment to the environment. Secondary containment details are provided in Section 6.2.3 and SGT system details are provided in Section 6.5.1.

6.5.3.3 Standby Liquid Control (SLC) System

The SLC system is initiated as directed by procedure to inject sodium pentaborate solution into the reactor pressure vessel when there is evidence of fuel damage following a LOCA. Flow from the break will carry the boron to the suppression pool. Maintaining the pool pH above 7.0 for the duration of the accident will minimize the re-evolution of gaseous iodine. See Section 9.3.5.

Table 6.5-1

Standby Gas Treatment System
Component Description Per Unit

Charcoal Filters

Type	Deep bed
Quantity	Two in series
Design Flow (acfm)	4800
Media	Charcoal
Radioiodine removal	Not less than 99.5% methyl iodide, tested at 30°C and 70% relative humidity
Depth of each bed (in.)	4
Pressure drop, clean (in. wg)	2.0
Residence time each train (sec.)	≥ 0.5
Ignition temperature, minimum (°C)	330
Iodine desorption temperature range (°F)	250-300 (low threshold)
Charcoal halogen loading, gm	67 (maximum theoretical loading for 30-day accident duration) 2577 (absorbing capability)

HEPA Filters

Type	High efficiency, dry
Quantity	Two banks, four filters each
Capacity (acfm)	4800 each bank
Media	Fiberglass U.L. Class 1
Efficiency (%)	99.97 with 0.3-micron DOP aerosol
Pressure drop, clean (in. wg)	1.0 nominal

Prefilter

Type	Medium efficiency, dry
Quantity	One bank, four filters
Design Flow (acfm)	4800
Media	Fiberglass
Efficiency (%)	80-85%
Pressure drop, clean (in. wg)	0.5 nominal

Table 6.5-1

Standby Gas Treatment System
Component Description Per Unit (Continued)

Heater

Type	Electric, on-off
Quantity	Two banks
Capacity (kW)	20.7 (nominal each bank)
Stages	Three

SGT System Exhaust Fans

Type	Centrifugal (with volume control)
Quantity	Two 100% capacity units
Design Flow (acfm)	4800
Static Pressure (in. wg)	16 nominal
Drive	Direct
Motor (hp)	25

Demister

Type	Multiple bed
Quantity	One bank, four filter units
Design Flow (acfm)	4800
Media	Metal baffle plate and fiberglass pads
Pressure drop, clean (in. wg)	0.8 nominal

6.6 INSERVICE INSPECTION OF ASME CODE CLASS 2 AND CLASS 3 COMPONENTS

The structural integrity of ASME Code Class 2 and 3 components is maintained as required by the Inservice Inspection (ISI) Program in accordance with 10 CFR 50.55a. With the structural integrity of any component not conforming to the above requirements, the structural integrity will be restored to within its limits or the affected component will be isolated. For Class 2 components, isolation will be accomplished prior to increasing reactor coolant system temperature above 200°F.

The Preservice Inspection Program Plan (Reference 5.2-6) addresses preservice inspections of Quality Groups B and C (ASME Boiler and Pressure Vessel Code, Section III Class 2 and 3) components as required by Section XI of the ASME Boiler and Pressure Vessel Code.

The Inservice Inspection Program (ISI) addresses inservice inspections of Quality Groups B and C (ASME Boiler and Pressure Vessel Code, Section III, Class 2 and 3) components as required by Section XI of the ASME Boiler and Pressure Vessel Code.

6.7 MAIN STEAM ISOLATION VALVE LEAKAGE CONTROL SYSTEM

The main steam isolation valve leakage control system (MSLC) is isolated and deactivated. The structural integrity of piping systems and components left in place is maintained.