5. REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 Summary Description

The AP1000 Design Control Document (DCD) Tier 2, Section 5.1, "Reactor Coolant System and Connected Systems," provides a summary description of the AP1000 reactor coolant system (RCS) and connected systems, as well as their design bases. DCD Tier 2, Sections 5.2 through 5.4 provide detailed design descriptions of reactor coolant pressure boundary integrity, reactor vessel (RV), and component and system design, respectively. Following is an overview of the AP1000 RCS and connected systems. Sections 5.2 through 5.4 of this report provide the staff's evaluation of these systems.

DCD Tier 2, Figures 5.1-1 through 5.1-3 show the schematic and layout of the AP1000 RCS and its principal auxiliary systems. The RCS consists of two heat transfer circuits (loops), each with a U-tube steam generator (SG), two reactor coolant pumps (RCPs), a single hot leg pipe, and two cold leg pipes for circulation of reactor coolant. The RCS also includes the pressurizer, interconnecting piping, valves, and instrumentation for operational control, actuation, and monitoring of plant safety systems. All RCS equipment is located in the reactor containment.

The reactor coolant pressure boundary (RCPB) provides a barrier against the release of radioactivity generated within the reactor. It is designed to provide a high degree of integrity throughout operation of the plant.

5.1.1 Design Bases

DCD Tier 2, Section 5.1.1, "Design Basis," lists the following design bases for the RCS and its major components:

- The RCS transfers to the steam and power conversion system the heat produced during power operation, as well as the heat produced when the reactor is subcritical, including the initial phase of plant cooldown.
- The RCS transfers to the normal residual heat removal system (RNS) the heat produced during the subsequent phase of plant cooldown and cold shutdown.
- During power operation and normal operational transients (including the transition from forced to natural circulation), the RCS removes heat and maintains fuel condition within the operating bounds permitted by the reactor control and protection systems.
- The RCS provides the water used as the core neutron moderator and reflector, conserving thermal neutrons and improving neutron economy. The RCS also provides the water used as a solvent for the neutron absorber used in chemical shim reactivity control.
- The RCS maintains the homogeneity of the soluble neutron poison concentration and the rate of change of the coolant temperature, so that uncontrolled reactivity changes do not occur.

- The RCS pressure boundary accommodates the temperatures and pressures associated with operational transients.
- The reactor vessel supports the reactor core and control rod drive mechanisms.
- The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, the pressurizer accommodates volume changes in the reactor coolant.
- The reactor coolant pumps supply the coolant flow necessary to remove heat from the reactor core and transfer it to the steam generators.
- The steam generators provide high-quality steam to the turbine. The tubes and tube sheet boundary prevent the transfer of radioactivity generated within the core to the secondary system.
- The RCS piping contains the coolant under operating temperature and pressure conditions, and limits leakage (and activity release) to the containment atmosphere. The RCS piping contains demineralized and borated water that is circulated at the flow rate and temperature consistent with achieving the reactor core thermal and hydraulic performance.
- The RCS is monitored for loose parts, as described in DCD Tier 2, Section 4.4.6.4.
- Applicable industry standards and equipment classifications of RCS components are identified in DCD Tier 2, Tables 3.2-1 and 3.2-3.
- The reactor vessel head is equipped with suitable provisions for connecting the head vent system, which meet the requirements of Title 10, Section 50.34 (f)(2)(vi), of the *Code of Federal Regulations* (10 CFR 50.34(f)(2)(vi)) (Three Mile Island [TMI] Action Item II.B.1, "Reactor Coolant System Vents"), as described in DCD Tier 2, Section 5.4.12.
- The pressurizer surge line and each loop spray line connected with the RCS are instrumented with resistance temperature detectors (RTDs) attached to the pipe to detect thermal stratification.

5.1.2 Design Description

The following components are included in the AP1000 RCS:

- the reactor vessel, including the control rod drive mechanism housings
- the reactor coolant pumps, comprising four canned motor pumps, which transfer fluid through the entire reactor coolant and reactor systems

- the primary portion of the steam generators containing reactor coolant, including the channel head, tube sheet, and tubes
- the pressurizer, which is attached by the surge line to one of the reactor coolant hot legs
- the pressurizer safety valves and automatic depressurization system valves
- the reactor vessel head vent isolation valves
- the interconnecting piping and fittings between the system components
- the piping, fittings, and valves leading to connecting auxiliary or support systems

DCD Tier 2, Tables 5.1-1 through 5.1-3 specify the principal system pressures, temperatures, flow rates, system design and operating parameters, and thermal-hydraulic parameters of the RCS.

During operation, the RCPs circulate pressurized water through the RV and the SGs respectively. The water, which serves as coolant, moderator, and solvent for boric acid (chemical shim control), is heated as it passes through the reactor core. Heat is removed from the water and transferred to the main steam system in the SGs. The RCPs then return the water to the RV to repeat the heat removal cycle.

RCS pressure is controlled by the operation of the pressurizer, which maintains water and steam in equilibrium through the activation of electrical heaters, a water spray, or both. Steam is formed by the heaters or condensed by the water spray to control pressure variations resulting from expansion and contraction of the reactor coolant.

Spring-loaded safety valves are connected to the pressurizer to provide overpressure protection for the RCS. These valves discharge into the containment atmosphere. Two redundant sets of the first-three-stage automatic depressurization system (ADS) valves are also attached to the pressurizer. These valves discharge steam and water (in three stages of operation) through spargers located in the in-containment refueling water storage tank (IRWST). The IRWST is part of the AP1000 passive core cooling system.

Two fourth-stage ADS valves are connected by two redundant paths to the RCS hot legs. These valves discharge directly to the containment atmosphere.

The RCS is also served by a number of auxiliary systems:

- the chemical and volume control system (CVS)
- the passive core cooling system (PXS)
- the residual heat removal system (RNS)
- the steam generator system (SGS)
- the primary sampling system
- the liquid radwaste system
- the component cooling water system (CCS)

5.1.3 System Components

DCD Tier 2, Section 5.1.3, "System Components," describes the major components of the RCS. The following sections discuss each of the components in detail.

5.1.3.1 Reactor Vessel

The RV is cylindrical, with a hemispherical bottom head and a removable, flanged, hemispherical upper head. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. The vessel interfaces with the reactor internals, the integrated head package, and the reactor coolant loop piping. It is supported by the containment building concrete structure.

The design of the AP1000 RV closely matches the existing vessel designs of other Westinghouse three-loop plants. New features have been incorporated into the AP1000 without departing from the proven features of existing vessel designs.

The RV has inlet and outlet nozzles positioned in two horizontal planes between the upper head flange and the top of the core. The nozzles are located in this configuration to provide an acceptable cross-flow velocity in the vessel outlet region, and to facilitate optimum layout of the RCS equipment. The inlet and outlet nozzles are offset, with the inlet positioned above the outlet, to allow midloop operation for removal of a main coolant pump without discharge of the core.

Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom, and flows up through the core to the outlet nozzles.

5.1.3.2 Steam Generators

Each SG is a vertical shell and U-tube evaporator with integral moisture separating equipment. The basic SG design and features are similar to previous Westinghouse SGs, including replacement SG designs.

The DCD describes several design enhancements to the AP1000 SGs, including nickel-chromium-iron (Ni-Cr-Fe) Alloy 690 thermally treated (TT) tubes on a triangular pitch; improved antivibration bars (AVBs); single-tier separators; enhanced maintenance features; and a primary-side channel head design that allows easy access and maintenance by robotic tooling. The AP1000 SG employs tube supports utilizing a broached hole support plate design. All tubes in the SG are accessible for sleeving, if necessary.

The basic function of the AP1000 SG is to transfer heat from the single-phase reactor coolant water, through the U-shaped heat exchanger tubes, to the boiling, two-phase steam mixture in the secondary side of the SG. The SG separates dry, saturated steam from the boiling mixture, and delivers the steam to a nozzle which in turn delivers the steam to the turbine. Water from the feedwater system replenishes the SG water inventory by entering the SG through a feedwater inlet nozzle and feedring.

In addition to its steady-state performance function, the SG secondary side provides a water inventory that is continuously available as a heat sink to absorb primary side high-temperature transients.

5.1.3.3 Reactor Coolant Pumps

Each reactor coolant pump (RCP) is a high-inertia, high-reliability, low-maintenance, hermetically sealed canned-motor pump that circulates reactor coolant through the RV, loop piping, and SGs. The AP1000 design uses four RCPs. Two pumps are coupled with each SG. The pumps are integrated into the SG channel head.

The integration of the pump suction into the bottom of the SG channel head eliminates the cross-over leg of the coolant loop piping; reduces the loop pressure drop; simplifies the foundation and support system for the SG, pumps, and piping; and reduces the potential for uncovering the core by eliminating the need to clear the loop seal during a small loss-of-coolant accident (LOCA).

Each AP1000 RCP is a vertical, single-stage, centrifugal pump designed to pump large volumes of coolant at high pressures and temperatures. The pump impeller attaches to the rotor shaft of the driving motor, which is an electric induction motor. Both the stator and rotor are encased in corrosion-resistant cans constructed and supported to withstand full system pressure. Shaft seals are eliminated in the AP1000 design because of the RCPs canned design. To provide the rotating inertia needed for flow coastdown, a uranium alloy flywheel is attached to the pump shaft.

A variable frequency drive provides speed control and minimizes the pump motor size. This reduces the requirements for motor power during pump startup from cold conditions. The variable frequency drive is used only during heatup and cooldown when the RCS temperature is less than 232.2 °C (450 °F). During power operations, the drive is isolated and the pump runs at constant speed.

5.1.3.4 Primary Coolant Piping

RCS piping is configured with two identical main coolant loops, each of which employs a single 78.34-centimeter (cm) (31-inch (in.)) inside diameter hot leg pipe to transport reactor coolant to an SG. The two RCP suction nozzles are welded directly to the outlet nozzles on the bottom of the SG channel head. Two 55.88-cm (22-in.) inside diameter cold leg pipes in each loop (one per pump) transport reactor coolant back to the RV to complete the circuit. The loop configuration and material ensure that pipe stresses are sufficiently low for the primary loop and large auxiliary lines to meet the "leak-before-break" (LBB) requirements. Thus, pipe rupture restraints are not required, and the loop is only analyzed for pipe ruptures in the small auxiliary lines that do not meet the LBB requirements.

5.1.3.5 Pressurizer

The pressurizer is the principal component of the RCS pressure control system. This is a vertical, cylindrical vessel with hemispherical top and bottom heads, where liquid and vapor are maintained in equilibrium at saturated conditions.

The top head includes a 10.16-cm (4-in.) spray nozzle and two 35.56-cm (14-in.) nozzles for connecting the safety and depressurization valve inlet headers. Electrical heaters are installed through the bottom head. The heaters are removable for replacement. The bottom head contains the nozzle for attaching the surge line. This line, which connects the pressurizer to a hot leg, provides for the flow of reactor coolant into and out of the pressurizer during RCS thermal expansions and contractions.

5.1.3.6 Pressurizer Safety Valves

The two pressurizer safety valves are spring-loaded and self-actuated with back-pressure compensation. Valve set pressure is 17.23 MegaPascal (MPa) (2485 pounds per square inch gauge (psig)). The combined capacity of the two valves is determined by the requirement not to exceed the maximum RCS pressure limit during the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III defined Level B service condition, loss-of-load transient, (i.e., 110 percent of the RCS design pressure of 17.23 MPa (2485 psig)). Thus, the design of the AP1000 pressurizer safety valves complies with the requirements of the ASME Code, Section III.

5.1.3.7 Automatic Depressurization Valves

Several of the passive safety features of the AP1000 design depend on depressurization of the RCS. This is accomplished by the ADS valves located above the pressurizer (Stages 1 to 3), and attached to the RCS hot legs (Stage 4). The Stage 1 to 3 valves are arranged in six parallel sets (two valves in series), opening in three stages. The Stage 4 ADS valves consist of four paths, each path having two valves in series. To mitigate the consequences of the various accident scenarios, the ADS valves are arranged to open in a prescribed sequence determined by the core makeup tank (CMT) level and a sequence timer. DCD Tier 2, Sections 5.4.6, "Automatic Depressurization System Valves," and 6.3, "Passive Core Cooling System," include a more detailed description of the ADS valves.

5.1.4 System Performance Characteristics

DCD Tier 2, Section 5.1.4, "System Performance Characteristics," discusses the thermal-hydraulic parameters, system performance parameters, and supporting design procedures used to establish the performance characteristics of the AP1000 RCS. The detailed design procedure establishes a best-estimate flow and conservatively high- and low-flows for the applicable mechanical and thermal design considerations. In establishing the range of design flows, the design procedure accounts for uncertainties in the component flow resistance and in the pump head-flow capability. The procedure also accounts for the uncertainties in the technique used to measure flow in the operating plant. DCD Tier 2, Section 5.1.4, also defines the four reactor coolant flows that are applied in plant design considerations, which are described as follows.

5.1.4.1 Best-Estimate Flow

The best-estimate flow is the most likely value for the normal, full-power operating condition. This flow value is determined by the best estimate of fuel, RV, SG, and piping flow resistance, and on the best estimate of the RCP head and flow capability. No uncertainties are assigned to either the system flow resistance or the pump head. The best-estimate flow provides the basis for the other design flows required for the system and component design. The best-estimate flow and head also define the performance requirement for the RCP. DCD Tier 2, Table 5.1-3, lists system pressure losses on the basis of the best-estimate flow.

Although the best-estimate flow is the most likely value to be expected in operation, more conservative flow rates (i.e., thermal design flow rate and mechanical design flow rate) are applied in the thermal and mechanical designs.

5.1.4.2 Minimum-Measured Flow

The minimum-measured flow is specified in the technical specifications (TS) as the flow that must be confirmed or exceeded by the flow measurements obtained during plant startup. The AP1000 thermal design procedure uses this flow rate in the reactor core departure from nucleate boiling (DNB) analysis. In the thermal design procedure methodology for DNB analysis, flow measurement uncertainties are combined statistically with fuel design and manufacturing uncertainties. The measured reactor coolant flow will most likely differ from the best-estimate flow because of uncertainties in the hydraulics analysis and inaccuracies in the instrumentation used to measure flow. The measured flow is expected to fall within a range around the best-estimate flow. The magnitude of the expected range is established by statistically combining the system hydraulics uncertainty with the total flow rate within the expected range, less any excess flow margin that may be provided to account for future changes in the hydraulics of the RCS.

5.1.4.3 Thermal Design Flow

The thermal design flow is the conservatively low-flow value used for thermal-hydraulic analyses when the design and measurement uncertainties are not combined statistically. Additional flow margin must, therefore, be explicitly included. The thermal design flow is derived by subtracting the plant flow measurement uncertainty from the minimum-measured flow. The thermal design flow is approximately 4.5 percent less than the best-estimate flow. The thermal design flow is confirmed when the plant is placed in operation. DCD Tier 2, Table 5.1-3, presents important design parameters founded on the thermal design flow.

5.1.4.4 Mechanical Design Flow

Mechanical design flow is the conservatively high-flow value used as the basis for the mechanical design of the RV internals, fuel assemblies, and other system components. Mechanical design flow is established at 104 percent of the best-estimate flow.

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.1 Compliance With Code and Code Cases

General Design Criteria (GDC) 1, "Quality Standards and Records," requires that nuclear power plant structures, systems, and components (SSCs) important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. This requirement is applicable to both pressure-retaining and non-pressure-retaining SSCs that are part of the RCPB, as well as other systems important to safety. Where generally recognized codes and standards are used, they must be identified and evaluated to determine their adequacy and applicability.

5.2.1.1 Compliance With 10 CFR 50.55a

Pursuant to Title 10 of the Code of Federal Regulations (10 CFR) 50.55a, "Codes and Standards," *components important to safety are subject to the following requirements:*

- RCPB components must meet the requirements for ASME Class 1 (Quality Group (QG) A) components as specified in ASME Code, Section III, except for those components that meet the exceptions described in 10 CFR 50.55a(c)(2). These components may be classified as Class 2 (QG B), or Class 3 (QG C).

- In accordance with 10 CFR 50.55a(d) and (e), components classified as QG B and QG C must meet the requirements for Class 2 and 3 components, respectively, as specified in ASME Code, Section III.

DCD Tier 2, Tables 3.2-1 and 3.2-3, and applicable piping and instrumentation drawings (P&ID) collectively classify the mechanical and pressure-retaining components of the RCPB that do not meet the exclusion requirements, discussed above, as ASME Code, Section III, Class 1 components. These Class 1 components are designated QG A in conformance with Regulatory Guide (RG) 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," Revision 3. The staff has compared DCD Tier 2, Tables 3.2-1 and 3.2-3, to the corresponding tables in the AP600 DCD and found no significant differences.

The staff has evaluated the quality group classifications discussed in Section 3.2.2 of this report, and concludes that the AP1000 mechanical and pressure-retaining components in the RCPB have been acceptably classified as QG A, in accordance with 10 CFR 50.55a. These quality group classifications are also consistent with applicable portions of Section 5.2.1.1 of the U.S. Nuclear Regulatory Commission's (NRC) Standard Review Plan (SRP).

In addition to the QG A components of the RCPB, certain lines that will perform a safety function and that meet the exclusion requirements of 10 CFR 50.55a(c)(2) are classified as QG B or QG C, in accordance with Positions C.1 or C.2 of RG 1.26, Revision 3. These will be constructed as ASME Code, Section III, Class 2 or Class 3 components.

As discussed in DCD Tier 2, Sections 5.2.1.1, "Compliance with 10 CFR 50.55a," and 5.2.1.3, "Alternate Classification," the portion of the chemical and volume control system (CVS) inside containment that is defined as part of the RCPB uses an alternate quality group classification. This portion of the CVS is classified as non-safety, Class D. The safety-related classification of the RCPB ends at the third isolation valve between the RCS and the CVS (see DCD Tier 2, Figure 9.3.6-1). This is considered to be an alternate to the usual classification of the RCPB. Title 10, Section 50.55a(a)(3), of the Code of Federal Regulations allows alternatives to 10 CFR 50.55a(c) requirements, if the proposed alternative design provides an acceptable level of quality and safety. The applicant provided the following design enhancements to the Class D portion of the CVS as an alternate design:

- The isolation valves between the RCS and the CVS are ASME Class 1 valves designed and qualified for design conditions that include closing against blowdown full flow with full system differential pressure. In addition, although these valves are not classified as pressure isolation valves, DCD Tier 2, Table 3.9-16, provides a commitment that at each refueling outage, these valves will be leak tested to the same leak rate criteria that is specified in the AP1000 TS for pressure isolation valves. Implementation of these additional leak rate tests will provide redundant leaktight barriers, when required, in each of the lines that connect the RCS and CVS.

- The AP1000 design also contains a third valve in each of the lines that connect the RCS and CVS. These third valves are in addition to the Class 1 valves discussed in the above design enhancement, and they will provide additional assurance that the RCS will be isolated in the event of a CVS failure.

- Although the Class D portions of the CVS are nonseismic, those portions inside containment will be analyzed to the same seismic design criteria as that accepted by the staff for seismic Category II piping. Section 3.12.3.7 of this report discusses the staff's acceptance of this criteria. The seismic Category II analyses will provide adequate assurance that the loads resulting from a safe-shutdown earthquake will not result in a loss of structural integrity of the CVS piping.

- All of the Class D portion of the CVS is constructed of or clad with corrosion-resistant material, such as Type 304 or Type 316 stainless steel, that is compatible with the reactor coolant. In addition, this portion of the CVS is designed to a design pressure of 21.4 MPa (3100 psi), which exceeds the RCS design pressure.

Based on the above design enhancements to the Class D portion of the CVS, the staff finds that the alternative design provides an acceptable level of quality and safety and, therefore, is acceptable.

DCD Tier 2, Section 5.2.1.1, states that the baseline code used to support the AP1000 DCD is ASME Code, Section III, 1998 Edition, up to and including the 2000 Addenda. However, the ASME Code, Section III, 1989 Edition, 1989 Addenda will be used for Articles NB-3200, NB-3600, NC-3600, and ND-3600 in lieu of the later edition and addenda. The use of these edition and addenda meets the requirements of 10 CFR 50.55a(b) and the associated modification in 10 CFR 50.55a(b)(1)(iii) and is, thus, acceptable. Any proposed change to the use of the ASME Code editions or addenda by a Combined License (COL) applicant will require NRC approval prior to implementation.

The ASME Code is Tier 1 information and the specific edition and addenda are designated Tier 2* because of the continually evolving design and construction practices (including inspection and examination techniques) of the Code. Establishing a specific edition and addenda during the design certification stage might result in inconsistencies between design and construction practices during the detailed design and construction stages. The ASME Code involves a consensus process to reflect the evolving design and construction practices of the industry. Although reference to a specific edition of the Code for the design of the ASME Code class components and their supports is necessary to reach a safety finding during the design certification stage, it is also important that the construction practices and examination methods of an updated Code be consistent with the design practices established at the design certification stage.

To avoid this potential inconsistency for the AP1000 pressure-retaining components and their supports, proposed changes to the specific edition and addenda require NRC approval at the COL stage before implementation. This provides the COL applicant with the option to revise or supplement the referenced Code edition with portions of later Code editions and addenda to ensure consistency between the design and construction practices. However, the staff acknowledges that a need may exist to establish certain design parameters from a specific Code edition or addenda during its design certification review, particularly when the information is important to developing a significant aspect of the design or is used by the staff to reach its final safety determination. Various sections of this report reflect such considerations, as necessary. Therefore, all ASME Code Class 1, 2, and 3 pressure-retaining components and their supports shall be designed in accordance with the requirements of ASME Code, Section III, using the specific edition and addenda given in the DCD.

The COL applicant should ensure that the design is consistent with the construction practices (including inspection and examination methods) of the ASME Code edition and addenda, as endorsed in 10 CFR 50.55a. DCD Tier 2, Section 5.2.6.1, "ASME Code and Addenda," contains a commitment that the COL applicant will address consistency of the design with the construction practices (including inspection and examination methods) of the later ASME Code edition and addenda. The staff finds this to be an acceptable commitment. This is COL Action Item 5.2.1.1-1.

On the basis of the above evaluations, the staff concludes that the construction of all AP1000 ASME Code, Class 1, 2, and 3 components and their supports will conform to the appropriate ASME Code editions and addenda, as well as the Commission's regulations. Furthermore, component quality will be commensurate with the importance of the safety function of all such components and their supports. The staff finds this to be an acceptable basis for satisfying GDC 1.

5.2.1.2 <u>Applicable Code Cases</u>

The only acceptable ASME Code cases that may be used for the design of ASME Code Class 1, 2, and 3 piping systems in the AP1000 standard plant are those either conditionally or unconditionally approved in RG 1.84, "Design, Fabrication, and Materials Code Case Acceptability, ASME Section III, Division 1," and that are in effect at the time of design certification, or determined to be conditionally acceptable as discussed above. However, the COL applicant may submit, with its COL application, future Code cases that are endorsed in RG 1.84 at the time of the application, provided that they do not alter the staff's safety findings on the AP1000 certified design. In addition, the COL applicant should submit those Code cases which are in effect at the time of the COL application that are applicable to RG 1.147, "Inservice Inspection Code Case Acceptability — ASME Section XI, Division 1," and RG 1.192, "Operation and Maintenance Code Case Acceptability, ASME OM [Operation and Maintenance] Code."

The staff notes that ASME Code Case 2142-1, "F-Number Grouping for Ni-Cr-Fe, Classification UNS N06052 Filler Metal, Section IX," and CC 2143-1, "F-Number Grouping for Ni-Cr-Fe, Classification UNS W86152 Welding Electrode, Section IX," are also listed in the DCD Tier 2, Table 5.2-3. RG 1.84 will not include these cases because they are not ASME Section III Code cases. However, the staff considers these cases to be acceptable because they include the weld metal to be used in the welding of Ni-Cr-Fe Alloy 690, which the staff endorsed and accepted for use in its safety evaluation report (SER) for the Electric Power Research Institute (EPRI), "Advanced Light Water Reactor Utility Requirements Document," Volume III.

On the basis of the above evaluation, the staff concludes that the ASME Code cases in DCD Tier 2, Table 5.2-3, either meet the guidelines of RG 1.84, or have been reviewed and endorsed by the staff and are acceptable for use in the AP1000 design. The applicant's compliance with the requirements of these Code cases will result in a component quality that is commensurate with the importance of the safety functions of the components. This satisfies the requirements of GDC 1 and, therefore, is acceptable.

5.2.2 Overpressure Protection

In the AP1000 design, overpressure protection for the RCS and the steam system pressure boundaries is provided by the pressurizer safety valves (PSVs) and the SG safety valves (SGSVs) during normal power operation, and a relief valve in the suction line of the normal residual heat removal system (RNS) during low-temperature operation, in conjunction with the action of the reactor protection system. There are 2 PSVs, 12 SGSVs with 6 valves located in the safety-related portion of the main steam piping running upstream of the main steam isolation valve (MSIV), and 1 relief valve in the suction line of the RNS. Combinations of these systems provide compliance with the overpressure protection requirements of ASME Code, Section III, Paragraphs NB-7300 and NC-7300, for pressurized-water reactor (PWR) systems. The ASME Code requires that the total relieving capacity be sufficient to prevent a pressure rise of more than 10 percent above the design pressure of the RCS and the SGs under any expected system pressurization transient conditions. The RNS suction relief valve for low-temperature overpressure protection (LTOP) prevents the RCS from exceeding the pressure-temperature limits determined by the analyses described in ASME Code, Section III, Appendix G.

The following general design criteria in 10 CFR Part 50, Appendix A, specify requirements regarding the RCS design:

- GDC 15, "Reactor Coolant System Design," requires the RCS and associated auxiliary, control, and protection systems to be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences.

- GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," requires the RCPB to be designed with sufficient margin to assure that the boundary behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized.

Section 5.2.2 of the SRP, including Branch Technical Position (BTP) Reactor Systems Branch (RSB) 5-2, describes the acceptance criteria that demonstrate that a plant design complies with GDC 15 and 31. Therefore, the staff reviewed the AP1000 overpressure protection in accordance with SRP Section 5.2.2 and BTP RSB 5-2. In particular, the staff reviewed the following DCD Tier 2 sections:

- Section 5.2.2, "Overpressure Protection"
- Section 5.4.5, "Pressurizer"
- Section 5.4.7, "Normal Residual Heat Removal System"
- Section 5.4.9, "RCS Pressure Relief Devices"
- Section 5.4.11, "Pressurizer Relief Discharge System"
- Section 10.3.2.2.2, "Main Steam Safety Valves"

5.2.2.1 Overpressure Protection during Power Operation

During power operation, 2 PSVs, 12 SGSVs, and the reactor protection system provide overpressure protection for the RCS to maintain the primary and secondary pressures within 110 percent of their respective design pressures. DCD Tier 2, Section 10.3.2.2.2, "Main Steam Safety Valves," discusses the details of the SGSV design. DCD Tier 2, Table 10.3.2-2, lists the design data, including set pressures and relieving capacities. DCD Tier 2, Table 5.4-17, specifies the design parameters of the PSVs. The minimum required relief capacity is 340,194 kilograms per hour (Kg/hr) (750,000 pounds mass per hour (lbm/hr)) per valve at 3 percent accumulation, and the set pressure is 17.23 MPa ± 0.17 MPa (2485 psig ± 25 psi). The discharge of the PSV is routed through a rupture disk to the containment atmosphere. The rupture disk, which has a pressure rating substantially less than the set pressure of the PSV, is designed to contain leakage past the PSV.

The size of the PSVs is determined by an analysis of a complete loss of steam flow to the turbine, with the reactor operating at 102 percent of rated power. This design-basis event bounds other events that could lead to overpressure of the RCS, if adequate overpressure protection were not provided. Such overpressure events include loss of electrical load and/or turbine trip, uncontrolled rod withdrawal at power, loss of reactor coolant flow, loss of normal feedwater, and loss of offsite power to the station auxiliaries. The total PSV capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient. In this analysis, feedwater flow is also assumed to be lost, and steam relief through the SGSVs is considered when the secondary side pressure reaches 103 percent of the SG shell design pressure. No credit is taken for operation of the pressurizer level control system, pressurizer spray system, rod control system, steam dump system, or steamline power-operated relief valve. The reactor is maintained at full power with no credit taken for reactor trip or reactivity feedback during the transient. A 3 percent set pressure accumulation is also considered for the PSV relief. These assumptions meet the acceptance criteria of Section 5.2.2, II.A of the SRP.

With these assumptions, the results of the design-basis safety analysis of a turbine trip event with a complete loss of steam load from full power, described in DCD Tier 2, Section 15.2.3, "Turbine Trip," show that the actuation of the PSVs maintains the RCS pressure below 110 percent of the design pressure. This analysis demonstrates that the capacities and setpoints of the PSVs and SGSVs are sufficient to ensure that the pressures of RCS and the SGs remain below 110 percent of their design pressures. Design-basis safety analyses of the other overpressure events described in DCD Tier 2, Sections 15.3, "Decrease in Reactor Coolant System Flow Rate," and 15.4, "Reactivity and Power Distribution Anomalies," also demonstrate the same conclusion. The PSV and SGSV setpoints and relieving capacities, therefore, are acceptable.

The PSV set pressure of between 17.06 MPa (2460 psig) and 17.41 MPa (2510 psig), (i.e., 17.23 MPa (2485 psig) ± 1.0 percent tolerance), is specified in the limiting condition for operation (LCO) in AP1000 TS 3.4.6, "Pressurizer Safety Valves," described in DCD Tier 2, Chapter 16, "Technical Specifications." The PSVs are part of the RCPB and are ASME Code Class 1 components. These valves are tested and analyzed using the design transients, loading conditions, seismic considerations, and stress limits for Class 1 components discussed in DCD Tier 2, Sections 3.9.1, "Special Topics for Mechanical Components," 3.9.2, "Dynamic Testing and Analysis," and 3.9.3, "ASME Code Classes 1, 2, and 3 Components, Component Supports, and Core Support Structures." The corresponding sections of this report discuss the staff's evaluation of these sections. In addition, the PSVs are subjected to the EPRI verification program established to address the requirements of 10 CFR 50.34(f)(2)(x) to qualify PSVs for operation in all fluid conditions expected under operating conditions, transients, and accidents. Chapter 20, Item II.D.1, "Testing Requirements," of this report addresses this issue. The PSVs (i.e., RCS-PL-V005A and RCS-PL-V005B) are also subject to the surveillance requirement of AP1000 TS 3.4.6.1 and the inservice testing program (IST) requirements specified in DCD Tier 2, Table 3.9-16.

As discussed above, the overpressure protection design for the AP1000, at power operating conditions, complies with the guidelines of Section 5.2.2 of the SRP and the requirements of GDC 15 and, therefore, is acceptable.

5.2.2.2 Overpressure Protection during Low-Temperature Operation

Section 5.2.2 of the SRP specifies that the LTOP system be designed in accordance with the guidance of BTP RSB 5-2. The BTP specifies that the LTOP system be capable of relieving pressure during all anticipated overpressurization events at a rate sufficient to prevent the applicable TS and Appendix G limits for the RCS from being exceeded while the plant is operating at low temperatures. BTP RSB 5-2 also specifies that the LTOP system meet the ASME Code, Section III requirements, as well as RGs 1.26 and 1.29, "Seismic Design Classification," regarding quality group and seismic design classifications. In addition, Section 5.2.2 of the SRP specifies that the LTOP system must be operable during startup and shutdown conditions below the enable temperature defined in BTP RSB 5-2. The enable temperature is defined as the water temperature corresponding to a metal temperature of at least the reference nil-ductility temperature (RT_{NDT}) plus 50 °C (90 °F) at the beltline location.

The LTOP system for the AP1000 is provided by the relief valve in the suction line of the RNS, which discharges to the containment sump. Administrative controls and plant procedures aid in controlling RCS pressure during low-temperature operation. Normal plant operating procedures maximize the use of a steam or gas bubble in the pressurizer during periods of low-pressure, low-temperature operation. For those low-temperature modes when operation with a water-solid pressurizer is possible, the RNS relief valve provides LTOP for the RCS. As discussed in DCD Tier 2, Section 5.4.7, "Normal Residual Heat Removal System," the RNS relief valve and associated piping are safety-related. DCD Tier 2, Table 3.2-3, specifies that the RNS suction pressure relief valve (RNS-PL-V021) is an AP1000 Class B component, seismic Category I, which meets the ASME Code, Section III, Class 2 requirements. Because the relief valve is connected to the piping between the containment isolation valves for the system, it also provides a containment boundary function and is subject to the containment isolation requirements discussed in DCD Tier 2, Section 6.2.3, "Containment Isolation System." The relief valve is also subject to inservice test requirements described in DCD Tier 2, Table 3.9-16. In addition, AP1000 TS LCO 3.4.14, "Low-Temperature Overpressure Protection (LTOP) System," requires operability of the RNS suction relief valve for low-temperature, overpressure protection during shutdown modes of operation, including Mode 4 operation when any cold leg temperature is below 135 °C (275 °F). When the LTOP is enabled, the relief valve will automatically open for overpressure protection when the RCS pressure exceeds the RNS relief valve setpoint. In response to the staff's request for additional information (RAI) 440.036, the applicant stated that the LTOP enable temperature of 135 °C (275 °F) is based on the PSVs for RCS overpressure protection when the RCS temperature is above 135 °C (275 °F). As indicated in DCD Tier 2, Table 5.3-3, the end-of-life RT_{NDT} for the AP1000 RV is expected to be approximately 10 °C (50 °F). Therefore, the staff finds that the LTOP enable temperature of 135 °C (275 °F) is acceptable because it is significantly higher than the enable temperature defined by BTP RSB 5-2 (i.e.,RT_{NDT}+ 50 °C (90 °F) at the beltline location).

The sizing and set pressure of the RNS relief valve for LTOP are founded on the sizing analysis performed to prevent the RCS pressure from exceeding the lower of either 110 percent of the RNS system design pressure of 6.31 MPa (900 psig), or the applicable reactor vessel pressure/temperature (P/T) limits described in DCD Tier 2, Section 5.3.3, "Pressure-Temperature Limits." In its response to RAI 440.036 (Revision 2), the applicant stated that based on the nominal steady-state P/T limits applicable up to 54 effective full-power years (EFPYs), the lowest Appendix G limit from DCD Tier 2, Figures 5.3-2 and 5.3-3, is 4.38 MPa (621 psig). Therefore, the RNS relief valve is sized to the Appendix G limit of 4.38 MPa (621 psig). The RNS relief valve sizing is based on the following two types of events:

(1) the mass addition transient caused by a makeup/letdown mismatch
(2) the heat addition transient caused by an inadvertent start of one inactive RCP

These events result in bounding mass and energy input conditions relative to other credible events, such as the inadvertent actuation of the pressurizer heaters, loss of residual heat removal with RCS heatup as a result of decay heat and pump heat, and inadvertent hydrogen addition. The design-basis analyses for the sizing of the RNS relief valve for LTOP protection assumes that transients occur while the pressurizer is in water-solid condition. The mass input event assumes the injection of water into the RCS from the operation of both makeup pumps and letdown isolated with a maximum makeup/letdown mismatch flow of 40.1 cubic meters per hour (m^3/h) (177 gallons per minute (gpm)), which is limited by the cavitating venturi located in the discharge header of the CVS system makeup pumps. The case of an inadvertent restart of one RCP is postulated to occur over a range of reactor coolant temperatures between 37.8 °C and 93.3 °C (100 °F and 200 °F), and the water in the SG secondary side 27.8 °C (50 °F) hotter than the primary-side water. The assumption of a 27.8 °C (50 °F) temperature difference as the initial condition for the energy input transient conservatively bounds the cooldown operation controlled by the procedure. To prevent the possibility of a heat input transient, thereby limiting the required flow rate of the RNS suction relief valve, TS LCO 3.4.14 imposes an administrative limit for the LTOP protection system that does not allow an RCP to be started with the pressurizer level above 92 percent and the RCS temperature above 93.3 °C (200 °F).

This analysis is performed using the methodology described in the NRC-approved topical report, WCAP-14040-NP-A, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," issued January 1998. The analysis does not consider single active failure of the RNS relief valve because it is a self-actuated spring relief valve, and the single active failure does not apply to passive valves. Based on the energy input transient, the minimum RNS relief valve capacity of 192.7 m^3/h (850 gpm) is calculated at an RCS pressure equivalent to the valve setpoint of 3.55 MPa (500 psig) plus 10 percent accumulation, or 3.89 MPa (550 psig). With this setpoint, the peak pressure at the discharge of the RNS is no higher than 5.52 MPa (786 psig), and the peak pressure in the RCS is approximately 4.33 MPa (614 psig). For the mass addition transient, the maximum flow rate is 40.1 m^3/h (177 gpm), which is much less than the RNS relief valve capacity. Therefore, the peak pressure at the inlet to the RNS relief valve will be no higher than the valve's full-open pressure of 3.89 MPa (550 psig).

Based on the information above, the relief valve would mitigate the limiting LTOP transient while maintaining the RCS pressure at less than the Appendix G limit. The minimum required capacity of the RNS relief valve is 192.7 m^3/h (850 gpm). DCD Tier 2 Table 5.4-17 provides the RNS relief valve design parameters (i.e., the nominal set pressure of 192.7 m^3/h (850 gpm), nominal set pressure of 3.55 MPa (500 psig), and full-open pressure, with 10 percent accumulation, of 3.89 MPa (550 psig)).

The RNS relief valve setpoint of 3.55 MPa (500 psig) was derived based on the lower of 110 percent of the RNS design pressure or the RCS P/T limit of 4.38 MPa (621 psig), which was obtained from the bounding P/T heatup and cooldown curves specified in DCD Figures 5.3-2 and 5.3-3. These P/T limit curves are generic limiting curves for the AP1000 RV design based on the copper and nickel material composition, as described in DCD Tier 2, Table 5.3-1, and 54 EFPY. If the specific AP1000 P/T curves are not bounded by the curves of DCD Figures 5.3-2 and 5.3-3, either due to different RV material composition or plant operation greater than 54 EFPYs, the RNS relief valve setpoint must be reevaluated.

Since the RT_{NDT} of the RV material increases as exposure to neutron fluence increases, as a result of the neutron embrittlement effect, the operating P/T limit curves need to be periodically adjusted to accommodate the actual shift in the nil-ductility temperature. The RCS P/T limit curves are specified in the pressure-temperature limits report (PTLR), as required by AP1000 TS LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits." The bases for AP1000 TS 3.4.14 notes that each time the PTLR curves are revised, the LTOP system must be reevaluated to ensure that its functional requirements can still be met using the RNS suction relief valve or the depressurized and vented RCS condition. In DCD Tier 2, Section 5.3.6.1, the applicant requires that the COL applicant address the use of plant-specific P/T limit curves relative to the RV material composition during its procurement of the RV. In addition, the COL applicant should address the use of these curves during the evaluation of the LTOP system, including the setpoint pressure for the RNS relief valve, as noted in AP1000 TS BASES B3.4.14. This is COL Action Item 5.2.2.2-1.

Based on the above evaluation, the staff concludes that the appropriate set pressure will be used for the RNS relief valve to ensure that the P/T limits are not exceeded. The AP1000 LTOP system meets BTP RSB 5-2 and, therefore, is acceptable.

5.2.3 Reactor Coolant Pressure Boundary Materials

The staff reviewed DCD Tier 2, Section 5.2.3, "Reactor Coolant Pressure Boundary Materials," in accordance with Section 5.2.3, "Reactor Coolant Pressure Boundary Materials," of the SRP to ensure that the materials are compatible with the primary coolant water.

The materials must meet the following requirements:

- GDC 1 and 10 CFR 50.55a(a)(1) require that structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

- GDC 4 requires that structures, systems, and components important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.

- GDC 14 requires that the RCPB shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

- GDC 30 requires that components that are a part of the RCPB shall be designed, fabricated, erected, and tested to the highest quality standards practical.

- GDC 31 requires that the RCPB shall be designed with sufficient margin to assure that, when stressed under operation, maintenance, testing, and postulated accident conditions, it will behave in a nonbrittle manner and with the probability of rapidly propagating fracture minimized.

- Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 establishes the quality assurance requirements for the design, construction, and operation of those systems that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public.

- Appendix G, "Fracture Toughness Requirements," to 10 CFR Part 50 specifies the fracture toughness requirements for ferritic materials of the pressure-retaining components of the RCPB.

The staff reviewed the materials specifications; compatibility of materials with the reactor coolant; fabrication; and processing of ferritic materials; and fabrication and processing of austenitic stainless steel. Sections 5.2.3.2 through 5.2.3.5 of this report discuss the acceptability of these elements.

5.2.3.1 Summary of Technical Information

DCD Tier 2, Table 5.2-1, "Reactor Coolant Pressure Boundary Materials Specification," lists the material specifications for the principal pressure-retaining applications in the Class 1 primary components and reactor coolant system piping. This list includes the RV components, SG components, RCP, pressurizer, CMT, and the passive residual heat removal (PRHR) heat exchanger (HX).

The use of Ni-Cr-Fe alloy in the RCPB design of the AP1000 is limited to Alloy 690. The SG tubes are made of thermally treated Alloy 690. The non-safety-related portion of the CVS inside containment is constructed of materials compatible with the reactor coolant, and is made of or clad with corrosion-resistant material equivalent to the corrosion resistance of Types 304 and 316 alloys. Cast austenitic stainless steel (CASS) components do not exceed a ferrite content of 30 ferrite number (FN).

The RCS water chemistry is controlled to minimize corrosion and is routinely analyzed for verification. The design of the CVS allows for the addition of chemicals to the RCS to control pH, scavenge oxygen, control radiolysis reactions, and maintain corrosion product particulates below specified limits.

The ferritic low-alloy and carbon steels used in the principal pressure-retaining applications have corrosion-resistant cladding material for surfaces exposed to the reactor coolant. This corrosion resistant material is at least equivalent to Types 304 and 316 austenitic stainless steel alloys or Ni-Cr-Fe alloy, martensitic stainless steel, and precipitation-hardened stainless steel. Austenitic stainless steel and Ni-Cr-Fe alloy base materials with primary pressure-retaining applications are used in solution-annealed or thermally treated conditions.

Hardfacing material in contact with the reactor coolant is primarily a qualified low- or zero-cobalt alloy equivalent to Stellite-6. The use of cobalt base alloy is minimized. Low- or zero-cobalt alloys used for hardfacing or other applications in which cobalt alloys have been previously used are qualified using wear and corrosion tests. Cobalt-free, wear-resistant alloys considered for this design include those developed and qualified in nuclear industry programs.

The thermal insulation used on components subject to elevated temperature during system operation is made of reflective stainless steel. In addition, compounded materials are silicated to provide protection of austenitic stainless steels against stress corrosion caused by accidental wetting from the environment.

The limiting SG and pressurizer reference temperatures for RT_{NDT} temperatures are guaranteed at 21.1 °C (70 °F) for the base materials and weldments. In addition, these materials meet the 67.7 newton-meter (N-m) (50 foot-pounds (ft-lbs)) absorbed energy and 0.089 cm (35 mils) lateral expansion requirements at -12.2 °C (10 °F).

Austenitic stainless steel materials used in the fabrication, installation, and testing of nuclear steam supply components and systems are handled, protected, stored, and cleaned to minimize contamination that could lead to stress-corrosion cracking (SCC). Tools used in abrasive work operations on austenitic stainless steel do not contain, and are not contaminated with, ferritic carbon steel or other materials which could contribute to intergranular cracking or SCC.

The welding of austenitic stainless steel is controlled to mitigate the occurrence of microfissuring or hot cracking in the weld.

5.2.3.2 Material Specifications

The specifications for pressure-retaining ferritic materials, nonferrous metals, and austenitic stainless steels, including weld materials, that are used for each component in the RCPB must meet GDC 1, "Quality Standards and Records"; GDC 30, "Quality of Reactor Coolant Pressure Boundary"; and 10 CFR 50.55a, "Codes and Standards," as they relate to quality standards for design, fabrication, erection, and testing. These requirements are met for materials specifications by complying with the appropriate provisions of the ASME Code, and by applying the Code cases included in RG 1.84. In addition, in the NRC letter from C.I. Grimes to D.J. Walters, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," dated May 19, 2000, the staff discusses an acceptable screening method, based upon Molybdenum content, casting method, and ferrite content, for determining the susceptibility of CASS components to thermal aging.

The staff reviewed DCD Tier 2, Section 5.2.3.1, "Materials Specifications," to determine the suitability of the RCPB materials for this application. The AP1000 design conforms with the guidance provided in RG 1.84, as well as the appropriate provisions of the ASME Code.

The staff noted that the DCD states that the RCP pressure housing will be made from SA 351 or SA 352 CF3A material, and that the RCP pressure boundary valve bodies may be castings of SA 351 CF3A. In addition, the DCD states that CASS will not exceed a ferrite content of 30 FN. Since CASS RCP pressure boundary components are subject to thermal embrittlement, the staff requested, in RAI 251.012 that the applicant discuss (1) the impact of this aging effect on the integrity of these components, (2) the consideration of the thermal embrittlement mechanism in the design and material selection for the RCPB components, and (3) the need for inspections to detect this aging effect. In its response, the applicant stated that based on its experience with casting materials, the selection of low-carbon-grade casting, i.e., CF3A, and control of the material specifications to below 20 FN, thermal aging should not have a significant impact on the integrity of the components. The applicant responded further that the ASME Code inservice inspections (ISI) will be relied on to detect the effects of any thermal aging. The response to RAI 251.012 discusses the COL action items regarding these inspections in a proposed change to DCD Tier 2, Section 5.2.6, "Combined License Information Items." The applicant also committed to revising the limit of the ferrite content of CASS to a maximum of 20 FN. The applicant revised DCD Tier 2, Section 5.2.3.1, "Materials Specifications," to include this revised FN. The staff reviewed the revised DCD and, subject to the clarification discussed below, finds it acceptable because it conforms to the guidance in RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal," and the criteria discussed in the May 19, 2000, letter from C.I. Grimes to D.J. Walters.

The staff requested the applicant to clarify in the DCD that the method used to calculate the δ-ferrite is based on Hull's equivalent factors or a method producing an equivalent level of accuracy (i.e., ± 6 percent deviation between the measured and calculated values), as discussed in the May 19, 2000, letter from C.I. Grimes to D.J. Walters. This was Open Item 5.2.3-1. Subsequent to the issuance of the DSER, the applicant revised the DCD to indicate that the calculation of ferrite content is based on Hull's equivalent factors. Therefore, since the application is consistent with the staff's position on a method the staff finds acceptable for calculating the δ-ferrite in CASS, Open Item 5.2.3-1 is resolved.

5.2.3.3 <u>Compatibility of Materials with the Reactor Coolant</u>

The materials of construction employed in the RCPB that are in contact with the reactor coolant, contaminants, or radiolytic products must be compatible and must meet the requirements of GDC 4, "Environmental and Dynamic Effects Design Bases," as they relate to the compatibility of components with environmental conditions. The requirements of GDC 4 are met by complying with the applicable provisions of the ASME Code and with the regulatory positions of RG 1.44, "Control of the Use of Sensitized Stainless Steel."

The staff reviewed DCD Tier 2, Section 5.2.3.2, "Compatibility with Reactor Coolant," to determine the compatibility of the RCPB components with various environments. The AP1000 design conforms to the guidance provided in RG 1.44. In addition, ferritic low-alloy and carbon steels used in the principal pressure-retaining components are clad with a layer of austenitic stainless steel.

The staff noted the discussion of safe ends in DCD Tier 2, Section 5.2.3.2.2, "Compatibility of Construction Materials with Reactor Coolant." The staff requested, in RAI 252.002, that the applicant discuss the purpose of the safe ends and address the concern that if the purpose of the safe ends is to protect the austenitic stainless steel from sensitization, then the A-8 weld (which is also austenitic stainless steel) may become sensitized during postweld heat treatment of the component at 593.3 °C (1100 °F). The applicant stated in its response that the purpose of the safe ends is to protect the austenitic stainless steel from being heat-treated during field installation, which may cause sensitization. The applicant further elaborated that based on experience with the safe ends on current reactors, postweld heat treatment of the safe ends at the fabrication shop does not cause a sensitization concern.

The staff reviewed this response and determined that it is not entirely acceptable because the A-8 welds may include austenitic stainless steels, such as Types 304 and 316, that may become sensitized during postweld heat treatment. The staff reviewed the revised DCD in which the applicant further clarified the purpose of the safe ends and removed references to A-8 welds. The staff finds this clarification to be acceptable.

In addition, the staff finds that the materials for the AP1000 design are compatible with the reactor coolant and meet the requirements of GDC 4, "Environmental and Dynamic Effects Design Bases," because they meet the guidance provided in RG 1.44, which provides for corrosion resistance of ferritic low alloy steel and carbon steel components through the use of austenitic stainless steel cladding.

5.2.3.4 Fabrication and Processing of Ferritic Materials

The fracture toughness properties of the ferritic materials in the RCPB must meet the requirements of 10 CFR Part 50, Appendix G, GDC 1, as it relates to nondestructive testing (i.e., examination) to quality standards; GDC 14, "Reactor Coolant Pressure Boundary," as it relates to extremely low probability of rapidly propagating fracture and gross rupture of the RCPB; and GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," as it relates to nonbrittle behavior of materials and the probability of rapidly propagating fracture being minimized.

The fracture toughness requirements of GDC 14 and 31 are met through compliance with the acceptance standards in Article NB-2300 of ASME Code, Section III, and Appendix G, Article G-2000, to the ASME Code. The acceptance criteria for control of ferritic steel welding are met through compliance with the applicable provisions of the ASME Code and with the regulatory positions of RG 1.34, "Control of Electroslag Weld Properties"; RG 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components"; RG 1.50, "Control of Preheat Temperature for Welding of Low Alloy Steel"; and RG 1.71, "Welder Qualification for Areas of Limited Accessibility."

The nondestructive examination (NDE) requirements of GDC 1 for the examination of ferritic components are met through compliance with the ASME Code, Section III, Subarticle NB-2500.

The staff reviewed DCD Tier 2, Section 5.2.3.3, "Fabrication and Processing of Ferritic Materials," to ensure that the RCPB components satisfy the requirements regarding prevention of RCPB fracture, control of welding, and NDE.

The AP1000 design conforms with ASME Code, Section III, Subarticle NB-2300, to meet fracture toughness requirements in 10 CFR Part 50, Appendix G. The design also meets the controls for welding and material preservation by conforming to RGs 1.34, 1.43, 1.50, and an acceptable alternative to RG 1.71, as discussed below.

Appendix G to 10 CFR Part 50 requires the pressure-retaining components of the RCPB to be made of ferritic materials to meet the requirements for fracture toughness during system hydrostatic tests, and any condition of normal operation, including anticipated operational occurrences. For piping, pumps, and valves, this requirement is met through compliance with the requirements of ASME Code, Section III, Paragraph NB-2331 or NB-2332, and the C_V values specified in Table NB-2332(a)-1. The AP1000 design complies with these Code requirements and, therefore, satisfies the requirements of 10 CFR Part 50, Appendix G.

In addition, the AP1000 design meets the requirements of GDC 1 for NDE through its compliance with ASME Code, Section III, 1998 Edition, 2000 Addenda, as discussed in DCD Tier 2, Section 5.2.1.1, "Compliance with 10 CFR 50.55a."

The staff noted the discussion of welding material control in DCD Tier 2, Section 5.2.3.3.2, "Control of Welding." The staff requested, in RAI 252.003, that the applicant confirm that the storage and handling of the welding materials is also covered by ASME Code, Section III, Subarticle NB-4400. In its response, the applicant stated that the requirements of NB-4400 will be implemented in the fabrication and installation of components. In addition, DCD Tier 2, Section 5.2.3.3.2, will be modified to include ASME Code, Section III, Subarticle NB-4400. The staff reviewed the revised DCD and determined that it acceptably addressed this issue because the AP1000 design meets the appropriate ASME Code requirement for control of welding material.

The staff noted in DCD Tier 2, Appendix 1A, "Compliance with Regulatory Guides," that the applicant stated that the AP1000 design takes exception to RG 1.71. Specifically, the AP1000 design does not require qualification or requalification of welders for areas of limited accessibility consistent with current practice, as recommended in RG 1.71. The staff requested, in RAI 252.005, the applicant to explain how the AP1000 design will ensure that welds made in areas of limited accessibility and/or visibility meet the fabrication requirements of ASME Code, Section III, for welds that are not volumetrically examined. In its response, the applicant stated that, based on experiences in the fabrication of RCPB components, accessibility and visibility of welds which require only surface examination will not need welders qualified to RG 1.71 requirements. The applicant elaborated that all welds fabricated in shop can be set up using a mechanical positioner, and that various tools are available to support the required inspection.

The staff reviewed this response and determined that it is acceptable because the AP1000 design includes ASME Code, Section III, welder qualification requirements for the inspection of weld joints normally requiring a surface examination.

The staff finds that the AP1000 design meets Appendix G to 10 CFR Part 50 and GDC 1, 14, and 31 because it includes appropriate controls for the fabrication and processing of ferritic materials to ensure fracture toughness of the RCPB components, control of welding, and NDE commensurate with the safety function of the RCPB.

5.2.3.5 Fabrication and Processing of Austenitic Stainless Steel

Process control techniques must be included during all stages of component manufacturing and reactor construction to meet GDC 1, as it relates to nondestructive testing (i.e., examination) to quality standards; GDC 4; and 10 CFR Part 50, Appendix B, Criterion XIII, "Handling, Storing, and Shipping." These requirements prevent severe sensitization of the material, by minimizing exposure of the stainless steel to contaminants that could lead to SCC, and reduce the likelihood of component degradation or failure through contaminants.

The requirements of GDC 4 and 10 CFR Part 50, Appendix B, Criterion XIII, are met through compliance with the applicable provisions of the ASME Code and with the regulatory positions of RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal"; RG 1.34; RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel"; RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"; RG 1.44, "Control of the Use of Sensitized Stainless Steel"; and RG 1.71.

The NDE requirements of GDC 1 for the examination of austenitic components are met through compliance with ASME Code, Section III, Paragraphs NB-2550 through NB-2570.

The staff reviewed DCD Tier 2, Section 5.2.3.4, "Fabrication and Processing of Austenitic Stainless Steel," to ensure that austenitic stainless steel RCPB components are compatible with environmental conditions to avoid sensitization and SCC, are compatible with thermal insulation, have appropriate controls on welding and material preservation, and have appropriate NDE.

The AP1000 design conforms to ASME Code, Section II, for the final heat treatment of austenitic stainless steels; American Society for Testing and Materials (ASTM) A 262, Practice A or E for materials testing; and the following guidance for the controls for welding and material preservation in conjunction with ASME Code, Section III:

- RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal"
- WCAP-8324-A, "Control of Delta Ferrite in Austenitic Stainless Steel Weldments," for δ-ferrite verification as an alternative to RG 1.31
- RG 1.34, "Control of Electroslag Weld Properties"
- RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel"
- RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," with an acceptable exception as discussed in Section 17.3 of this report
- RG 1.44, "Control of the Use of Sensitized Stainless Steel"
- RG 1.71, "Welder Qualification for Areas of Limited Accessibility," with an acceptable alternative as discussed in Section 5.2.3.4 of this report

The thermal insulation used in the AP1000 design of the RCPB is acceptable because it conforms to the guidance in RG 1.36 for nonmetallic insulation with respect to acceptable levels of leachable contaminants in these materials.

The AP1000 design takes an exception to quality standard American National Standards Institute (ANSI) N.45.2.1-1973, as referenced in RG 1.37. Section 17.3 of this report provides a discussion of relevant quality assurance documents.

The AP1000 design meets the requirements of GDC 1 for NDE through its compliance with ASME Code, Section III, 1998 Edition, 2000 Addenda, as discussed in DCD Tier 2, Section 5.2.1.1, "Compliance with 10 CFR 50.55a."

The staff noted the discussion about the use of welding material that is not fully austenitic in DCD Tier 2, Section 5.2.3.4.6, "Control of Welding." The staff requested, in RAI 252.004, the applicant to list the exact materials exempted from the delta ferrite requirement for the AP1000 design, and the exact materials considered to be fully austenitic for welding applications. In its response, the applicant stated that the phrase "fully austenitic welding materials" refers to the regular austenitic stainless steel welding materials, such as Types 308 and 309. In addition, these austenitic stainless steel welding materials do include ferrite, and the DCD will require a minimum ferrite content of 5 FN.

The staff reviewed this response and determined that it is acceptable because the AP1000 design will specify a minimum ferrite content of 5 FN for fully austenitic welding materials, as recommended in RG 1.31. The staff reviewed the revised DCD, specifically, DCD Tier 2, Table 5.2-1, "Reactor Coolant Pressure Boundary Materials Specifications," and found that the specifications acceptably address the staff's concerns.

The staff concludes that the fabrication and processing of RCPB austenitic stainless steel meets GDC 1 and 4, and 10 CFR Part 50, Appendix B, Criterion XIII, because it conforms to the applicable provisions of the ASME Code and the regulatory positions in, or acceptable alternatives to, RGs 1.31, 1.34, 1.36, 1.37, 1.44, and 1.71.

5.2.3.6 Welding of Alloy 52/152/690 Materials

The staff has identified concerns related to the difficulties associated with welding of Alloy 690 material and the partial penetration J-groove welds of Alloy 690 materials, and the potential for welding defects to occur in Ni-Cr-Fe Alloy 52/152 weld materials. The staff requested Westinghouse to provide information on the steps it has taken to address this potential. This is Open Item 5.2.3-2.

Gas Tungsten Arc Welding (GTAW) and Shielded Metal Arc Welding (SMAW) processes are commonly used for the fabrication of Alloy 690 materials. Alloy 690 material can be welded with GTAW using Alloy 52 weld filler material. SMAW processes can be used with Alloy 152 electrodes for the fabrication of Alloy 690 material. Previous experience indicates that hot cracks are observed when Alloy 690 material is welded with 52/152 weld materials. When the SMAW process was used with an Alloy 152 electrode, oxide inclusions were observed in the weld, which necessitated removal by interpass grinding. To address potential weld quality concerns with Alloy 52/152 welds, Westinghouse proposes to control hot cracking by using proper welding techniques when welding is done using the GTAW and SMAW processes. Westinghouse also proposes additional weld inspections to ensure high-quality welds.

By letter dated December 12, 2003, Westinghouse indicated that liquid penetrant (PT) examination will be performed on the first weld layer, every one-quarter inch of the intermediate weld layers, and the final weld layer of the partial penetration J-groove welds of Alloy 690 materials. This requirement exceeds the inspection criteria specified in ASME Section III, Paragraph NB-5245, which requires PT examination after the first weld layer, successive PT examinations for every half-inch of weld metals, and PT examination of the final layer. The staff agrees with Westinghouse's proposal to increase the frequency of PT examination, which enhances the ability to detect hot cracks in the weld metal, thereby increasing the weld quality.

The staff requested that Westinghouse address the issue of pressure boundary leaks which occurred, in part, due to a lack of fusion in the partial penetration J-groove weld in the lower vessel head penetrations at South Texas Project, Unit 1. Westinghouse proposed new welding inspection requirements for ultrasonic testing (UT) of the interface where the partial penetration J-groove welds join the penetration tube. This examination will be performed to ensure that lack of fusion in the weld area is detected. The staff agrees with Westinghouse's proposed UT examination of partial penetration J-groove welds, which would be expected to detect lack of fusion defects in the weld. Westinghouse also indicated that the proposed PT examinations, followed by UT examination, are applicable to all partial penetration J-groove welds of Alloy 690 penetrations in ASME Section III, Class 1, RCS components. Westinghouse proposes to use the acceptance criteria specified in ASME Section III for PT examinations of the partial penetration J-groove welds. Westinghouse's proposal also includes the application of ASME Section XI acceptance criteria for the UT examinations of the partial penetration J-groove weld interfaces. The staff agrees that these steps will provide reasonable assurance that any weld defects will be detected and repaired during fabrication, and will enhance the quality of the partial penetration J-groove welds.

Westinghouse's proposal also discusses the NDE requirements for fabrication of full penetration butt welds. Westinghouse proposes to use the radiography and final pass PT requirements specified in ASME Section III, Paragraph NB-5000. Unlike the partial penetration J-groove welds, the fabrication of full penetration butt welds is less cumbersome, and the occurrence of weld defects is less frequent. Therefore, the staff agrees that Westinghouse's proposed NDE requirements will provide reasonable assurance that the quality of the RCPB butt welds will be maintained.

Based on the information provided by Westinghouse and discussed above, the staff concludes that Open Item 5.2.3-2 is resolved.

5.2.3.7 Low-Temperature Crack Propagation

The staff identified concerns regarding the susceptibility of high-chromium, nickel-based alloys (i.e., Alloy 690/52/152) to significantly lowered fracture toughness when tested in relatively low-temperature (e.g., less than 120 °C (248 °F)) hydrogenated water. This is Open Item 5.2.3-3. By letter dated December 31, 2003, Westinghouse provided information to address this concern.

Westinghouse cited a number of research studies in its December 31, 2003, letter (including references produced by Bettis and French researchers), and noted that reductions to fracture toughness and the resistance to crack propagation have been observed for certain high-chromium, nickel-based alloys, including Alloy 690 and weld metal Alloy EN52, in the presence of substantial concentrations of hydrogen in the service environment. This mode of material property degradation is referred to as low-temperature crack propagation (LTCP). LTCP has been observed to occur only under rising loads at relatively low temperatures and slow to moderate loading rates (less than 1000 MPa√meter/hr (909 Kip (1000 pounds) per inch squared √in./hr) for welded components). LTCP has been attributed to the stress-assisted accumulation of hydrogen adjacent to, and immediately ahead of, an advancing crack, leading to a decreasing resistance to intergranular crack propagation. The occurrence of the LTCP phenomenon requires time for the diffusion of hydrogen to the crack tip and, therefore, LTCP is not an issue for welded components subjected to rapid transients. LTCP has not been observed to occur from machined notches or at free surfaces in the absence of a sharp crack, because hydrogen does not concentrate in the diffuse strain field associated with such features. It should be noted, however, that the morphology of hot cracks (which have been shown to be potentially common in Alloy 52/152 welds) consists of rounded, interdendritic pores, and LTCP would not be expected to occur at such defects.

Based on the preceding discussion, Westinghouse concluded that four conditions are necessary for the occurrence of LTCP:

(1) relatively high concentrations of hydrogen in the environment and in the metal
(2) relatively low temperatures
(3) the presence of a sharp crack tip
(4) the presence of loads which rise at a moderate rate to levels great enough to fail the flawed material

Westinghouse conducted a review of the AP1000 primary system considering various cold temperature transients. Westinghouse concluded that the accident scenario that is most likely to result in the conditions necessary to support LTCP is the inadvertent opening of the isolation valve that separates the large-volume CMTs from the RV. This transient results in a large volume of room-temperature water flowing through the direct vessel injection (DVI) nozzle and, in particular, the Alloy 52/152 safe end butt welds used to connect the nozzle safe ends to the nozzle body. If it is assumed that the operators take no action, the temperature of the weld metal would quickly fall to near the temperature of the injection water. Thermal stresses would be induced in the pipe wall as a result of this cooling transient, which would be added to stresses from the primary system pressure.

The hydrogen concentration in a PWR primary water environment is in the range of 25 to 50 H_2/kg H_2O. Based on the research data applicable to Alloy 690 and Alloy EN52, this concentration of hydrogen is believed to be insufficient for LTCP. Although the available research did not include testing of Alloy EN152, for the purposes of this safety evaluation, it is presumed that Alloy 152 would exhibit similar properties to EN52. Therefore, Westinghouse concluded that the first condition for LTCP (i.e., the presence of relatively high concentrations of hydrogen in the environment and in the metal) is unlikely to be satisfied.

From the evaluation of the aforementioned accident scenario, Westinghouse concluded that the second condition for LTCP (i.e., the presence of low temperature) could be satisfied. Westinghouse noted that the third condition for LTCP (i.e., the presence of a sharp crack tip) is believed to be unlikely, except for the possible existence of a "lack-of-fusion" condition arising from the welding.

Westinghouse performed finite element analyses of the nozzle safe end using the thermal conditions discussed above. The results of this analysis indicate that the axial and hoop stresses were significantly below the yield stresses and, therefore, do not approach the level where LTCP would occur. Hence, Westinghouse concluded that the fourth condition for LTCP (i.e., the presence of loads which rise at a moderate rate to levels great enough to fail the flawed material) was unlikely to be satisfied.

Based on the information above, Westinghouse concluded that the conditions necessary for the occurrence of LTCP cannot take place in the AP1000 design. The staff agrees with Westinghouse's analysis and, on this basis, concludes that Open Item 5.2.3-3 is resolved.

5.2.3.8 Conclusions

The staff concludes that the design of the RCPB materials is acceptable and meets the requirements of GDC 1, 4, 14, 30, and 31; Appendices B and G to 10 CFR Part 50, and 10 CFR 50.55a.

5.2.4 RCS Pressure Boundary Inservice Inspection and Testing

The staff reviewed DCD Tier 2, Section 5.2.4, "Inservice Inspection and Testing of Class 1 Components," in accordance with Section 5.2.4, "Reactor Coolant Pressure Boundary (RCPB) Inservice Inspection and Testing," of the SRP. The requirements for periodic inspection and testing of the RCPB are acceptable if the inspection and test program satisfy Appendix A to 10 CFR Part 50, GDC 32, "Inspection of Reactor Coolant Pressure Boundary," and meet 10 CFR 50.55a, "Codes and Standards."

10 CFR 50.55a requires that ASME Code Class 1 components be designed with sufficient access to enable the performance of inservice examination of such components. The design must also meet the preservice examination requirements set forth in Section XI of the ASME Code applied to the construction of the particular component.

10 CFR Part 50, Appendix A, GDC 32, requires that components that are part of the RCPB be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity.

Compliance with the preservice and inservice examinations of 10 CFR 50.55a, as detailed in Section XI of the ASME Code, constitutes an acceptable basis for satisfying the periodic inspection and testing requirements of GDC 32.

The staff's evaluation of the inservice inspection and testing program for Class 1 components is divided into six sections, as described in the SRP. These include (1) the system boundary subject to inspection, (2) accessibility, (3) examination categories and methods, (4) inspection intervals, (5) evaluation of examination results, and (6) system leakage and hydrostatic pressure tests. Sections 5.2.4.2 through 5.2.4.7 of this report, respectively, discuss the acceptability of these elements.

5.2.4.1 Summary of Technical Information

The DCD states that preservice and inservice inspection and testing of ASME Code Class 1 pressure-retaining components (including vessels, piping, pumps, valves, bolting, and supports) within the RCPB will be performed in accordance with Section XI of the ASME Code, including addenda, according to 10 CFR 50.55a(g). This includes all ASME Code Section XI mandatory appendices.

The specific edition and addenda of the Code used to determine the requirements for the inspection and testing plan for the initial and subsequent inspection intervals is to be delineated in the inspection program. The Code includes requirements for system pressure tests and functional tests for active components. Section XI, IWA-5000, defines the requirements for system pressure tests and visual examinations. These tests verify pressure boundary integrity in conjunction with ISI.

DCD Tier 2, Section 3.9.6, "Inservice Testing of Pumps and Valves," discusses the inservice functional testing of valves for operational readiness. Since none of the pumps in the AP1000 are required to perform an active safety function, the operational readiness test program for the pumps is controlled administratively. Section 3.9.6 of this report evaluates this program.

Consistent with ASME Code and NRC requirements, the preparation of inspection and testing programs is the responsibility of the COL applicant for each AP1000. DCD Tier 2, Section 5.2.4, indicates that these programs will comply with the applicable ISI provisions of 10 CFR 50.55a(2). However, this reference should be 10 CFR 50.55a(b)(2). This is part of COL Action Item 5.2.4.1-1.

5.2.4.2 System Boundary Subject to Inspection

Consistent with the SRP, the applicant's definition of the RCPB is acceptable if it includes all pressure vessels, piping, pumps, and valves which are part of the RCS, or connected to the RCS, up to and including the following:

- the outermost containment isolation valve in system piping that penetrates the primary reactor containment
- the second of two valves normally closed during normal reactor operation in system piping that does not penetrate primary reactor containment
- the reactor coolant system safety and relief valves

DCD Tier 2, Section 5.2.4.1, indicates that Class 1 pressure-retaining components and their specific boundaries are included in the equipment designation list and the line designation list. Both of these lists are contained in the inspection program. ASME Code Class 1 components are designated as AP1000 equipment Class A. DCD Tier 2, Section 3.2.2, "AP1000 Classification System," discusses the system boundary for pressure-retaining components. The applicant's definition of the RCPB is consistent with the SRP and, therefore, is acceptable.

5.2.4.3 Accessibility

The design and arrangement of system components are acceptable if adequate clearance is provided in accordance with ASME Code, Section XI, Subarticle IWA-1500, "Accessibility."

DCD Tier 2, Section 5.2.4.2, describes accessibility for inspection. ASME Code Class 1 components are designed so that access is provided in the installed condition for visual, surface, and volumetric examination, as specified by the baseline ASME Code Section XI (1998 Edition, 2000 Addenda) and mandatory appendices. Design provisions, in accordance with ASME Code, Section XI, Subarticle IWA-1500, are incorporated in the design process for Class 1 components. Accessibility is acceptable because the AP1000 design incorporates the requirements of Subarticle IWA-1500.

5.2.4.4 Examination Categories and Methods

The examination categories and methods specified in the DCD are acceptable if they agree with the criteria in ASME Code, Section XI, Article IWB-2000, "Examination and Inspection." Every area subject to examination which falls within one or more of the examination categories in Article IWB-2000 must be examined, at least to the extent specified. The requirements of Article IWB-2000 also list the methods of examination for the components and parts of the pressure-retaining boundary.

The applicant's examination techniques and procedures used for preservice inspection or ISI of the system are acceptable, if they agree with the following criteria:

- The methods, techniques, and procedures for visual, surface, or volumetric examination are in accordance with Article IWA-2000, "Examination and Inspection," and Article IWB-2000, "Examination and Inspection," of ASME Code, Section XI.

- The methods, procedures, and requirements regarding qualification of nondestructive examination personnel are in accordance with Article IWA-2300, "Qualification of Nondestructive Examination Personnel."

- The methods, procedures, and requirements regarding qualification of personnel performing ultrasonic examination reflect the requirements provided in Appendix VII, "Qualification of Nondestructive Examination Personnel for Ultrasonic Examination," to Division 1 of ASME Code, Section XI. In addition, the performance demonstration for ultrasonic examination systems reflects the requirements provided in Appendix VIII, "Performance Demonstration for Ultrasonic Examination Systems," to Division 1 of ASME Code, Section XI.

DCD Tier 2, Sections 5.2.4.3, "Examination Techniques and Procedures," and 5.2.4.5, "Examination Categories and Requirements," discuss examination techniques, categories, and methods. The visual, surface, and volumetric examination techniques and procedures agree with the requirements of Subarticle IWA-2200 and Table IWB-2500-1 of ASME Code, Section XI. Examination categories and requirements are established according to Subarticle IWB-2500 and Table IWB-2500-1 of ASME Code, Section XI. Qualification of the NDE personnel is in compliance with Subarticle IWA-2300 of ASME Code, Section XI. The PT method or the magnetic particle method is used for surface examinations. Radiography, ultrasonic, or eddy current techniques (manual or remote) are used for volumetric examinations. DCD Tier 2, Section 5.2.1.1, indicates that the baseline used for the evaluation done in support of the safety analysis report and the design certification is the 1998 Edition, 2000 Addenda of ASME Code, Section XI. This edition and addenda of ASME Code, Section XI, requires the implementation of Appendix VII for qualification of NDE personnel for ultrasonic examination, and the implementation of Appendix VIII for performance demonstration for ultrasonic examination of reactor pressure boundary piping, RV welds, and RV head bolts. Because the examination methods and categories applied to Class 1 components will comply with the requirements of ASME Code, Section XI, as discussed above, the staff finds examination categories and methods for the AP1000 for Class 1 components to be acceptable.

In response to RAI 250.001, the applicant indicated that both the pressurizer and steam generator nozzle inside radius volumes are inspectable. The pressurizer inside radius volumes are intended to be examined from the outside diameter surface. The SGs inside radius volumes are intended to be examined either from the outside or inside surfaces. The staff finds this accessibility to be acceptable.

5.2.4.5 Inspection Intervals

The required examinations and pressure tests must be completed during each 10-year interval of service, hereinafter designated as the inspection interval. In addition, the scheduling of the program must comply with the provisions of Article IWA-2000, "Examination and Inspection," concerning inspection intervals of the ASME Code, Section XI.

DCD Tier 2, Section 5.2.4.4, "Inspection Intervals," discusses inspection intervals. Subarticles IWA-2400 and IWB-2400 of ASME Code, Section XI, define inspection intervals. The inspection intervals specified for the AP1000 Class 1 components are consistent with the definitions in Section XI of the ASME Code and, therefore, are acceptable.

5.2.4.6 Evaluation of Examination Results

The standards for examination evaluation in the program for flaw evaluation are acceptable if in agreement with the requirements of ASME Code, Section XI, Article IWB-3000, "Acceptance Standards." The proposed program regarding repairs of unacceptable indications or replacement of components containing unacceptable indications is acceptable if in agreement with the requirements of ASME Code, Section XI, Article IWA-4000, "Repair/Replacement Activities." The criteria that establish the need for repair or replacement are described in ASME Code, Section XI, Article IWB-3000, "Acceptance Standards."

DCD Tier 2, Section 5.2.4.6, "Evaluation of Examination Results," discusses the evaluation of examination results. Examination results are evaluated according to ASME Code, Section XI, IWA-3000 and IWB-3000, with flaw indications being evaluated according to IWB-3400 and Table IWB-3410-1. Repair procedures, if required, are evaluated according to ASME Code, Section XI. Based on this method of evaluating examination results, and the use of ASME Code rules for repair, the applicant's evaluation of examination results for AP1000 Class 1 components is acceptable.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

The pressure-retaining ASME Code Class 1 component leakage and hydrostatic pressure test program is acceptable if the program agrees with the requirements of ASME Code, Section XI, Article IWB-5000, "System Pressure Tests," and the TS requirements for operating limitations during heatup, cooldown, and system hydrostatic pressure testing. In some cases, the TS limitations may be more severe than those in Article IWB-5000.

DCD Tier 2, Section 5.2.4.7, discusses system leakage and hydrostatic pressure tests. System pressure tests will comply with IWA-5000 and IWB-5000 of ASME Code, Section XI. Based on this method of performing pressure tests, the staff finds the system leakage and hydrostatic pressure test for AP1000 Class 1 components to be acceptable.

5.2.4.8 Conclusions

Based on its evaluation of the system boundary subject to inspection, accessibility, examination categories and methods, inspection intervals, evaluation of examination results, and system leakage and hydrostatic pressure tests, the staff concludes that the periodic inspection and testing of the RCPB are acceptable. In addition, the inspection and test program satisfies GDC 32 because it meets the applicable requirements of ASME Code, Section XI, as endorsed in 10 CFR 50.55a.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection

The staff reviewed the capability of the AP1000 design to detect and, to the extent practical, identify the source of RCPB leakage. The staff reviewed the RCPB leakage detection design in accordance with the guidelines provided in SRP Section 5.2.5. Staff acceptance of the leakage detection design is on the basis of the design meeting the requirements of GDC 2, "Design Basis for Protection Against Natural Phenomena," as they relate to the capability of the design to maintain and perform its safety function following an earthquake, and on the design meeting the requirements of GDC 30, "Quality of Reactor Coolant Pressure Boundary," as they relate to the detection, identification, and monitoring of the source of reactor coolant leakage. Conformance with GDC 2 is on the basis of the leakage detection design meeting the guidelines of RG 1.29, "Seismic Design Classification," Positions C.1 and C.2. Conformance with GDC 30 is on the basis of the leakage detection design meeting the guidelines of RG 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," Positions C.1 through C.9. Leakage detection monitoring is also maintained in support of LBB criteria for high-energy fluid piping in containment. DCD Tier 2, Section 3.6.3, and Section 3.6.3, "Leak-Before-Break," of this report address the application of LBB criteria.

The staff also reviewed the RCPB leakage detection design for compliance with the requirements of the TMI issue designated by 10 CFR 50.34(f)(2)(xxvi). The TMI issue states that applicants should provide for leakage control and detection in the design of systems outside containment that contain (or might contain) total integrated dose (TID)-14844 source term radioactive materials following an accident.

RCPB leakage detection is accomplished using instrumentation and other components of several systems. Diverse measurement methods, including level, flow, and radioactivity measurements, are used for leakage detection. The equipment classification for each of the systems and components used for leakage detection is generally determined by the requirements and functions of the system in which it is located. Leakage detection and monitoring equipment is not required to be safety-related.

RCPB leakage is classified as either identified or unidentified leakage. Identified leakage includes (1) leakage from closed systems, such as RV seal or valve leakage, that is captured and conducted to a collecting tank, and (2) intersystem leakage into auxiliary systems and secondary systems. (Intersystem leakage must be considered in the evaluation of the reactor coolant inventory balance.) Other leakage is unidentified leakage.

5.2.5.1 Identified Leakage Detection

Sources of identified leakage in containment include leaks from the RV head flange, pressurizer safety relief valves, and automatic depressurization valves. In the course of plant operations, operating personnel may detect various minor leaks of the RCPB. If these leaks can be subsequently observed, quantified, and routed to the containment sump, this leakage is considered identified leakage.

Identified leakage, other than intersystem leakage, is collected in a closed reactor coolant drain tank (RCDT) located in the reactor cavity in containment. The RCDT vent is piped to the gaseous radwaste system to prevent release of radioactive gas to the containment atmosphere. Leakage detection alarms and indications are provided in the main control room (MCR). The RCDT, pumps, and sensors are part of the liquid radwaste system.

5.2.5.2 Intersystem Leakage Detection

DCD Tier 2, Section 5.2.5.2, states that the applicant considered possible intersystem leakage points across passive barriers or valves and their detection methods. Auxiliary systems connected to the RCPB incorporate design and administrative provisions that limit leakage. Such leakage is detected by increasing auxiliary system level, temperature, flow, or pressure; lifting relief valves; or increasing values of monitored radiation in the auxiliary system. The normal RNS and the CVS have the potential for intersystem leakage past closed valves.

An important, potentially identifiable, leakage path for reactor coolant is through the SG tubes into the secondary side of the SG. Identified leakage from the SG primary side is detected by one or a combination of the following methods:

- the condenser air removal radiation monitor
- the steam generator blowdown radiation monitor
- the main steamline radiation monitor
- laboratory analysis of condensate

In addition, leakage from the RCS to the component cooling water system (CCS) is detected by the CCS radiation monitor, by increasing surge tank level, by high flow downstream of selected components, or by some combination of the preceding.

5.2.5.3 Unidentified Leakage Detection

DCD Tier 2, Section 5.2.5.3, states that to detect unidentified leakage in containment, the following three diverse methods may be utilized to quantify and assist in locating the leakage:

(1) containment sump level
(2) reactor coolant system (RCS) inventory balance
(3) containment atmosphere radiation

In addition, other supplemental methods utilize containment atmosphere pressure, temperature, humidity, and visual inspection.

Position C.1 of RG 1.29 states that the SSCs listed in the RG, including their foundations and supports, should be designated as seismic Category I to ensure that they can withstand the effects of a safe-shutdown earthquake (SSE) and remain functional. DCD Tier 2, Section 5.2.5.4, states that the containment sump level monitor and the containment atmosphere radiation monitor are classified as seismic Category I.

Position C.2 of RG 1.29 states that those parts of the SSCs whose continued function is not required, but whose failure could reduce the functioning of any plant feature (identified in Position C.1) to an unacceptable safety level, or could result in an incapacitating injury to occupants of the MCR, should be designed and constructed so that an SSE would not cause such a failure. DCD Tier 2, Section 5.2.5, states that equipment classification for each of the systems and components used for leakage detection is generally determined by the requirements and functions of the system in which it is located. The leakage detection and monitoring equipment is not required to be safety-related.

Based on the above, the staff concludes that the design of systems and components used for leakage detection meets the guidelines of RG 1.29, Positions C.1 and C.2. Therefore, the design meets the requirements of GDC 2, as they relate to the capability of the systems and components to maintain and perform their safety function following an earthquake.

Position C.1 of RG 1.45 states that leakage to containment from identified sources should be collected or isolated so that flow rates are monitored separately from unidentified leakage, and the total flow rate can be established and monitored. As stated in Section 5.2.5.1 of this report, identified leakage is monitored separately for the RV head flange, pressurizer safety relief valves, and automatic depressurization valves.

Position C.2 of RG 1.45 states that leakage to containment from unidentified sources should be collected and the flow rate monitored with an accuracy of 3.79 liters/minute (L/min) (1 gpm) or better. DCD Tier 2, Section 5.2.5.3, states that the sensitivity of leakage detection monitoring is such that the containment sump level monitoring can detect a change of 1.89 L/min (0.5 gpm) in 1 hour. The containment sump level is monitored by three sensors. The third sensor is provided for redundancy in detecting main steamline leakage. The minimum detectable leak is 0.03 gpm, which has sufficient sensitivity to detect 0.25 gpm.

Position C.3 of RG 1.45 states that at least three separate methods should be used for leakage detection. Two of these methods should include (1) sump level and flow monitoring, and (2) airborne particulate radioactivity monitoring. The third method may be selected from monitoring either (1) condensate flow from the containment air coolers, or (2) containment airborne gaseous activity. DCD Tier 2, Section 5.2.5.3, states that containment sump level monitoring, containment atmosphere radiation monitoring, and RCS inventory balance are utilized in the AP1000 design to detect and monitor leakage in containment. In particular, the applicant selected the gaseous N_{13}/F_{18} monitor for containment atmosphere radiation monitoring. No credit is taken for airborne particulate radioactivity monitoring. DCD Tier 2, Section 5.2.5.3, states that humidity, temperature, and pressure monitoring are also used for alarms and provide an indirect indication of possible leakage in containment.

Position C.4 of RG 1.45 states that provisions should be made to monitor the systems connected to the RCPB for indications of intersystem leakage. Methods should include radioactivity monitoring and indicators to show abnormal water levels or flow in the affected systems. DCD Tier 2, Section 5.2.5.2, states that associated systems and components connected to the RCS have intersystem leakage monitoring devices. SG tube leakage is detected by the condenser air removal radiation monitor, the SG blowdown radiation monitor, the main steamline radiation monitor, or laboratory analysis of condensate. Leakage from the RCS to the CCS is detected by CCS radiation monitors, by increasing surge tank level, by high flow downstream of selected components, or by some combination of the preceding.

Position C.5 of RG 1.45 states that the sensitivity and response time of each method used to detect and monitor unidentified leakage in containment should be a minimum of 3.79 L/min (1 gpm) in less than 1 hour. In DCD Tier 2, Section 5.2.5.3.3, the applicant stated that the N_{13}/F_{18} radioactivity monitor can detect a 1.89 L/min (0.5 gpm) within 1 hour when the plant is at full power. The monitor is operable when the plant is above 20-percent power.

Position C.6 of RG 1.45 states that the leakage detection systems (LDSs) should be capable of performing their functions during and following an SSE. DCD Tier 2, Section 5.2.5.4, states that the containment sump level monitor and the containment atmosphere radiation monitor are classified as seismic Category I. Containment activity is monitored by the containment high-range radiation monitor, which is seismically qualified.

Position C.7 of RG 1.45 states that indicators and alarms for each LDS should be provided in the MCR. In addition, procedures for converting indications to a common leakage equivalent should be available to the operators. DCD Tier 2, Section 5.2.5.6, lists the alarms and/or indications for RCPB leakage provided in the MCR. The plant instrumentation system is a microprocessor-based system that accepts inputs from all RCPB leakage detection sensors and monitors. The containment sump level, containment atmosphere radioactivity, RCS inventory balance, and the flow measurements are provided as liters per minute (gallons per minute) leakage equivalent.

Position C.8 of RG 1.45 states that the LDSs should be equipped with provisions for operability testing and calibration during plant operation. DCD Tier 2, Section 5.2.5.5, states that periodic testing of the leakage detection monitors verifies the operability and sensitivity of detection equipment. These tests include calibrations and alignments during installation, periodic channel calibrations, functional tests, and channel checks. The instrumentation for RCPB leakage detection can be tested for operability during plant operation.

Position C.9 of RG 1.45 states that the TS should include limits for both identified and unidentified leakage, and should address the availability of various instruments to assure coverage at all times. DCD Tier 2, Chapter 16, defines the operability requirements for the RCS leakage detection instrumentation. The instrumentation is designed to verify its operability at all times. Should a detector fail (e.g., a signal outside the calibrated range or self-monitored trouble is detected), the plant instrumentation system will initiate a trouble alarm in the MCR, indicating that the readout of a specific monitor is questionable.

The staff compared AP1000 TS 3.4.7, "RCS Operational Leakage," and 3.4.9, "RCS Leakage Detection Instrumentation," to the Westinghouse Owners Group standard technical specification (WOG STS) 3.4.13, "RCS Operational Leakage," and 3.4.15, RCS Leakage Detection Instrumentation." AP1000 TS 3.4.9 requires one containment sump level channel and one containment atmosphere radioactivity monitor to be operable for Modes 1, 2, 3, and 4. However, there are two notes associated with this TS which relax the requirements for these two leakage detection instrumentation systems under certain conditions. The first note states that the containment atmosphere radioactivity monitor is only required to be Operable in Mode 1 with rated thermal power (RTP) greater than 20 percent. The second note states that containment sump level measurements cannot be used for leak detection, if the leakage is prevented from draining to the sump (e.g., such as by redirection to the IRWST by the containment shell gutter drains). In RAI 410.006, the staff asked what compensatory actions will be required to perform the function of RCS leakage detection if both notes are satisfied during Modes 1, 2, 3, and 4.

In response to RAI 410.006, the applicant stated that when the conditions in both notes are satisfied, there are compensatory actions required for RCS leakage detection. The containment atmosphere radioactivity monitor is not required to be operable any time that the plant power is less than 20 percent of the RTP; no additional compensatory leakage monitoring actions are needed when this instrument is not required to be operable. However, the containment sump level instrument is required to be operable in Modes 1, 2, 3, and 4 to provide RCS leakage detection, whether the containment radioactivity monitor is required or not.

The second note for the sump instrument does not eliminate the operability requirements for at least one containment sump level instrument channel in Modes 1, 2, 3, and 4 when the gutter drains are closed. The second note is intended to inform the operator that although the sump level instrument(s) may be operational, if the drain path for the containment shell gutter to the containment sump is closed, then the sump level measurement cannot perform its leak detection function. No condensate can return to the containment sump when the drain path is closed. Instead, the condensate will return to the IRWST. Condensate is able to drain to the sump as long as both series' drain path isolation valves are open.

If a drain path is closed, the containment sump level instruments do not meet the TS definition of operable. Therefore, when the drain path is closed, both channels are inoperable (even though both may be operating) and Condition A for LCO 3.4.9 must be entered. The compensatory action is to perform surveillance requirement (SR) 3.4.7.1 (RCS water inventory balance) more frequently (i.e., once every 24 hours instead of once every 72 hours). In addition, at least one containment sump channel must be restored to operable status within 72 hours. This means that both gutter drain path isolation valves must be opened. Once both series' isolation valves are open, then condensate will drain to the sump, and the available containment sump level instrument is considered to be operable. This explanation addressed the staff's concern and identified acceptable compensatory actions.. On the basis of the information above, the AP1000 design provides various instruments used to detect and monitor RCPB leakage, and the TS assures that leakage detections are available at all times.

From the information provided by the applicant and evaluated above, the staff concludes that the RCPB leakage detection design conforms to the guidelines of RG 1.45, Positions C.1 through C.9. Therefore, the design meets the requirements of GDC 30 as they relate to the detection, identification, and monitoring of the source of reactor coolant leakage.

The TMI issue designated by 10 CFR 50.34(f)(2)(xxvi) (Item III.D.1.1 of NUREG-0737) states that applicants should provide for leakage control and detection in the design of systems outside of containment that contain (or might contain) TID-14844 source term radioactive materials following an accident. Applicants will submit a leakage control program (including an initial test program), a schedule for retesting these systems, and the actions to be taken for minimizing leakage from such systems. The goal is to minimize potential exposures to workers and the public, and to provide reasonable assurance that excessive leakage will not prevent the use of system needed in an emergency. The applicant has addressed this TMI issue in DCD Tier 2, Section 1.9.3. The DCD states that the safety-related passive systems do not recirculate radioactive fluids outside containment following an accident. A non-safety-related system can be used to recirculate coolant outside of containment following an accident, but this system is not operated when high containment radiation levels exist. This satisfies the requirements of 10 CFR 50.34(f)(2)(xxvi).

Systems and components utilized for RCPB leakage detection provide reasonable assurance that structural degradation, which may develop in pressure-retaining equipment of the RCPB and result in coolant leakage during service, will be detected on a timely basis. Thus, corrective actions may be taken before such degradation can become severe enough to jeopardize the safety of the equipment, or before the leakage can increase to a level exceeding the capability of the makeup system to replenish the coolant loss.

On the basis of its review of information provided in the DCD, with clarification provided by the specified RAI responses, the staff concludes that the design of the systems and components for RCPB leakage detection is acceptable. The design meets the requirements of GDC 2 with respect to the capability of the AP1000 systems and components to maintain and perform their safety functions in the event of an earthquake. The design also meets the requirements of GDC 30 with respect to the detection, identification, and monitoring of the source of reactor coolant leakage. This conclusion is made on the basis of the following:

- The AP1000 design has fulfilled the requirements of GDC 2 with respect to the capability of systems and components to perform and maintain their safety functions in the event of an earthquake by meeting the guidelines of RG 1.29, Positions C.1 and C.2.
- The AP1000 design has fulfilled the requirements of GDC 30 with respect to the detection, identification, and monitoring of the source of reactor coolant leakage by meeting the guidelines of RG 1.45, Positions C.1 through C.9.
- The AP1000 design has fulfilled the requirements of 10 CFR 50.34(f)(2)(xxvi) with respect to minimizing leakage from systems outside containment that contain (or might contain) radioactive materials following an accident.

Therefore, the staff concludes that RCPB leakage detection for the AP1000 design conforms to the guidelines of SRP Section 5.2.5 and, therefore, is acceptable.

5.3 Reactor Vessel

DCD Tier 2, Section 5.3.1.2, "Safety Description," describes the AP1000 RV. The reactor vessel is cylindrical, with a hemispherical bottom head and a removable, flanged, hemispherical upper head. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. The vessel interfaces with the reactor internals, the integrated head package, and the reactor coolant loop piping, and is supported on the containment building concrete structure.

5.3.1 Reactor Vessel Design

The design of the AP1000 RV closely matches the existing vessel designs of the applicant's three-loop plants. New features for the AP1000 have been incorporated without departing from the proven features of existing vessel designs. The RV has inlet and outlet nozzles positioned in two horizontal planes between the upper head flange and the top of the core. The nozzles are located in this configuration to provide an acceptable cross-flow velocity in the vessel outlet region, and to facilitate optimum layout of the RCS equipment. The inlet and outlet nozzles are offset, with the inlet positioned above the outlet, to allow midloop operation for removal of a main coolant pump without discharge of the core.

Reactor coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom, and flows up through the core to the outlet nozzles.

5.3.2 Reactor Vessel Materials

The staff reviewed DCD Tier 2, Section 5.3.2, "Reactor Vessel Materials," in accordance with SRP Section 5.3.1, "Reactor Vessel Materials." The applicant's RV materials are acceptable if they meet codes and standards, and regulatory guidance commensurate with the safety function to be performed. This will ensure that the relevant requirements of 10 CFR 50.55a, "Codes and Standards"; 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements"; Appendix H, "Reactor Vessel Material Surveillance Program Requirements"; and GDC 1, 4, 14, 30, 31, and 32 are met. These requirements are discussed below.

- GDC 1 and 30, and 10 CFR 50.55a(a)(1) require structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

- GDC 4 requires structures, systems, and components important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.

- GDC 14 requires the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

- GDC 31 requires the RCPB shall be designed with sufficient margin to ensure that, when stressed under operation, maintenance, testing, and postulated accident conditions, it will behave in a nonbrittle manner, and minimize the probability of rapidly propagating fracture.

- GDC 32 requires the RCPB components shall be designed to permit an appropriate material surveillance program for the reactor pressure vessel.

- Appendix G to 10 CFR Part 50 specifies the fracture toughness requirements for ferritic materials of the pressure-retaining components of the RCPB. The staff reviewed the RV materials as they relate to the materials testing and acceptance criteria for fracture toughness contained in Appendix G. Pursuant to 10 CFR Part 50, Appendix G, the RV beltline materials must have Charpy upper shelf energy (USE) in the transverse direction for base material and along the weld for weld material, of no less than 101.7 N-m (75 ft-lbs) initially, and must maintain Charpy USE throughout the life of the vessel of no less than 67.8 N-m (50 ft-lbs).

- Appendix H to 10 CFR Part 50 presents the requirements for a materials surveillance program to monitor the changes in the fracture toughness properties of materials in the

RV beltline region resulting from exposure to neutron irradiation and the thermal environment. These requirements include conformance to ASTM E-185, "Standard Recommended Practices for Surveillance Tests for Nuclear Reactor Vessels." Compliance with Appendix H satisfies the requirements of GDC 32 regarding the provision of an appropriate materials surveillance program for the RV. The staff reviewed the RV materials to determine whether they meet the relevant requirements of Appendix H for determining and monitoring of fracture toughness.

5.3.2.1 <u>Summary of Technical Information</u>

5.3.2.1.1 Material Specifications

The applicant indicated that the material specifications are in accordance with the ASME Code requirements. All ferritic RV materials comply with the fracture toughness requirements of 10 CFR 50.55a and Appendices G and H to 10 CFR Part 50.

The chemical composition of the ferritic materials of the RV beltline are restricted to the maximum limits shown in DCD Tier 2, Table 5.3-1. Copper, nickel, and phosphorus content is restricted to reduce sensitivity to irradiation embrittlement in service.

5.3.2.1.2 Special Processes Used for Manufacturing and Fabrication

The RV is classified as AP1000 Class A. Design and fabrication of the RV is carried out in accordance with ASME Code, Section III, Class 1 requirements. The shell sections, flange, and nozzles are manufactured as forgings. The hemispherical heads are made from dished plates or forgings. The RV parts are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc processes.

5.3.2.1.3 Special Methods for Nondestructive Examination

The NDE of the RV and its appurtenances is conducted in accordance with ASME Code, Section III, requirements. Numerous examinations are also performed in addition these requirements.

<u>Ultrasonic Examination</u>. In addition to the required ASME Code straight-beam ultrasonic examination, angle-beam inspection over 100 percent of one major surface of plate material is performed during fabrication to detect discontinuities that may not be found by the straight-beam examination.

In addition to the ASME Code, Section III, NDE, full-penetration ferritic pressure boundary welds in the RV are ultrasonically examined during fabrication.

After hydrotesting, full-penetration ferritic pressure boundary welds in the RV, as well as the nozzle to safe end welds, are ultrasonically examined. These inspections are performed in addition to the ASME Code, Section III, NDE requirements.

Penetrant Examinations. The partial penetration welds for the control rod drive mechanism head adapters and the top instrumentation tubes are inspected by PT after the root pass, in addition to ASME Code requirements. Section 4.5.1 of this report provides additional information on the control rod drive mechanisms.

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

- Only the prod, coil, or direct contact method is used prior to the final postweld heat treatment.

- Only the yoke method is used after the final postweld treatment.

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

- magnetic particle examination of exterior vessel and head surfaces after the hydrostatic test

- magnetic particle examination of exterior closure stud surfaces and all nut surfaces after final machining or rolling

- magnetic particle examination of the inside diameter surfaces of carbon and low-alloy steel products that have their properties enhanced by accelerated cooling

Weld Examination. Magnetic particle examination of the welds attaching the closure head lifting lugs and refueling seal ledge to the RV is conducted after the first layer and again after each 1.27 cm (0.5 in.) of weld metal is deposited. All pressure boundary welds are examined after back-chipping or back-grinding operations.

5.3.2.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

DCD Tier 2, Section 5.2.3, "Reactor Coolant Pressure Boundary Materials," discusses welding of ferritic steels and austenitic stainless steels.

5.3.2.1.5 Fracture Toughness

Compliance with the requirements for fracture toughness testing included in ASME Code, Section III, Paragraph NB-2300, Appendix G to 10 CFR Part 50, and 10 CFR 50.61 assures adequate fracture toughness of the ferritic materials in the RV.

5.3.2.1.6 Material Surveillance

In the surveillance program, the evaluation of radiation damage is based on preirradiation testing of C_V and tensile specimens, and postirradiation testing of C_V, tensile, and ½-T compact tension fracture mechanics test specimens. The program evaluates the effect of radiation on the fracture toughness of RV steels based on the transition temperature and fracture mechanics approaches. The program conforms to ASTM E-185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," and 10 CFR Part 50, Appendix H.

The RV surveillance program incorporates eight specimen capsules. The eight capsules contain 72 tensile specimens, 480 C_v specimens, and 48 compact tension specimens. Archive material sufficient for two additional capsules and heat-affected zone (HAZ) materials will be retained. The applicant's schedule for removing the capsules for postirradiation testing includes the withdrawal of five capsules which is in accordance with ASTM E-185-82 and Appendix H to 10 CFR Part 50.

5.3.2.1.7 Reactor Vessel Fasteners

The RV closure studs, nuts, and washers are designed and fabricated in accordance with the requirements of ASME Code, Section III. The closure studs are fabricated from SA-540. The closure stud material meets the fracture toughness requirements of ASME Code, Section III, and 10 CFR Part 50, Appendix G. DCD Tier 2, Section 1.9 discusses the conformance of the AP1000 design with RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs." Nondestructive examinations are performed in accordance with ASME Code Section III.

5.3.2.2 Staff Evaluation

The staff reviewed DCD Tier 2, Section 5.3.2, "Reactor Vessel Materials," in accordance with Section 5.3.1, "Reactor Vessel Materials," of the SRP.

The NRC staff also reviewed the AP1000 RV materials to ensure that the relevant requirements of GDC 1 and 30 and 10 CFR 50.55a(a)(1) have been met as they relate to the material specifications, fabrication, and NDE. Compliance with these requirements will determine whether the RV materials are adequate to assure a quality product commensurate with the importance of the safety function to be performed. The material specifications for the AP1000 design are in accordance with ASME Code, Section III, requirements and 10 CFR Part 50, Appendix G. In addition, the design and fabrication of the RV is performed in accordance with ASME Code, Section III, Class I requirements. Furthermore, the RV and its appurtenances are fabricated and installed in accordance with the ASME Code, Section III, Paragraph NB-4100. The NDE of the RV and its appurtenances is conducted in accordance with ASME Code, Section III requirements. Examination of the RV and its appurtenances by NDE complies with Paragraph NB-5000, for normal methods of examination. The applicant identified other inspections, as previously stated, in addition to the ASME Code requirements of NDE (i.e., angle-beam inspections and dye penetrant examinations). The staff finds this acceptable because compliance with ASME Code, Section III, and 10 CFR Part 50, Appendix G, constitutes an acceptable basis for satisfying the requirements of GDC 1 and 30 and 10 CFR 50.55a(a)(1) as they relate to the material specifications, fabrication, and NDE of RV materials.

Section 5.2.3 of this report provides the staff's evaluation of the welding of ferritic steels and austenitic stainless steels, as well as addresses GDC 4.

DCD Tier 2, Table 5.3-1, provides the maximum limits for the elements in the materials of the RV beltline. The sulfur and phosphorus content of welds and forgings are limited to a maximum of 0.01 percent. Nickel is limited to 0.85 percent, copper to 0.03 percent, and vanadium to 0.05 percent. Data compiled in EPRI Report NP-933, "Nuclear Pressure Vessel Steel Database," indicate that this control on the level of material elements will provide the fracture toughness required to ensure the structural integrity of the RV, as specified by Appendix G to 10 CFR Part 50. The staff finds this acceptable.

The tests for fracture toughness of RV materials specified in the DCD are in accordance with ASME Code, Section III, Paragraph NB-2300, and 10 CFR Part 50, Appendix G. The staff confirmed that the applicant's initial C_v minimum upper shelf fracture energy levels for the RV beltline base metal transverse direction and welds are 101.7 N-m (75 ft-lbs). DCD Tier 2, Table 5.3-3, indicates that the end-of-life (EOL) values for the USE are greater than 67.8 N-m (50 ft-lbs) for the beltline forgings and welds. The staff confirmed this by using the calculations of RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," for the beltline forgings and welds. The predicted EOL Charpy USE and adjusted reference temperature for the RV materials are calculated in accordance with 10 CFR Part 50, Appendix G. The fracture toughness tests required by the ASME Code and Appendix G to 10 CFR Part 50 provide reasonable assurance that adequate safety margins against the possibility of nonductile behavior or rapidly propagating fracture can be established for all pressure-retaining components of the RCPB. This methodology will provide adequate safety margins during operating, testing, maintenance, and postulated accident conditions. Compliance with the provisions of Appendix G to 10 CFR Part 50 satisfies the requirements of GDC 14 and 31 and 10 CFR 50.55a regarding the prevention of fracture of the RCPB. Therefore, the staff finds that the applicant has adequately met the requirements of GDC 14 and 31, and 10 CFR 50.55a. Section 5.3.3.2 of this report provides the staff's evaluation of compliance with 10 CFR 50.61 (pressurized thermal shock).

The design of an RV must take into account the potential embrittlement of RV materials as a consequence of neutron irradiation and the thermal environment. GDC 32 requires that the RCPB components shall be designed to permit an appropriate material surveillance program for the reactor pressure vessel. Appendix H to 10 CFR Part 50 details the requirements for such a program.

The staff requested, in RAI 251.014, that the applicant describe the lead factors for the surveillance capsules. The staff requested that the applicant commit, in the AP1000 DCD, that an analysis will be performed for the COL application with regard to the capsule/holder model to more accurately define the surveillance capsule lead factors and azimuthal locations. In its response to RAI 251.014, the applicant clarified its approach to defining the surveillance capsule/holder location. In addition, the applicant revised the DCD to include an analysis that will be performed for the COL application with regard to the capsule/holder model to confirm the proposed surveillance capsule lead factors and azimuthal locations. The staff found this approach acceptable because this analysis would more accurately define the surveillance capsule lead factors and azimuthal locations. This is COL Action Item 5.3.2.2-1.

To meet the requirements of GDC 32, the AP1000 design includes provisions for a material surveillance program to monitor changes in the fracture toughness caused by exposure of the

RV beltline materials to neutron radiation. Appendix H to 10 CFR Part 50 requires that the surveillance program for the AP1000 RV meet the recommendations of ASTM E-185. ASTM E-185 was prepared to be applicable to plants designed for a 40-year life, whereas the design life of AP1000 is 60 years. ASTM E-185 recommends a minimum of four surveillance capsules for an RV with an EOL shift between 38 °C and 93 °C (100 °F and 200 °F). The AP1000 surveillance capsule program includes eight specimen capsules, with archive materials available for at least two additional complete replacement capsules. The staff verified that the surveillance test materials will be prepared from samples taken from the actual materials used in fabricating the beltline of the RV. In addition, the staff verified that the base metal, weld metal, and HAZ materials included in the program will be those predicted to be most limiting in terms of setting P/T limits for operation of the reactor to compensate for radiation effects during its lifetime. The staff found that the materials selection, withdrawal, and testing requirements for the AP1000 design are in accordance with those recommended in ASTM E-185-82. Compliance with the materials surveillance requirements of Appendix H to 10 CFR Part 50 and ASTM E-185 satisfies the requirements of GDC 32 regarding an appropriate surveillance program for the RV. Thus, the AP1000 design meets the requirements of GDC 32.

The applicant indicated that the material used to fabricate the closure studs will meet the fracture toughness requirements of Section III of the ASME Code and Appendix G to 10 CFR Part 50. NDE of the studs will be performed according to Section III of the ASME Code, Subarticle NB-2580. In addition, ISI will be performed according to Section XI of the Code, supplemented by Paragraph NB-2545 or NB-2546. The integrity of the AP1000 RV closure studs is assured by conformance with the recommendations of RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," thus satisfying the quality standards requirements of GDC 1 and 30 and 10 CFR 50.55a. Compliance with the recommendations of RG 1.65 also satisfies requirement in GDC 31 for the prevention of fracture of the RCPB and the requirements of Appendix G to 10 CFR Part 50, as detailed in the provisions of Section III of the ASME Code.

5.3.2.3 Conclusions

The staff concludes that the AP1000 RV material specifications, RV manufacturing and fabrication processes, NDE methods of the RV and its appurtenances, fracture toughness testing, material surveillance, and RV fasteners are acceptable and meet the material testing and monitoring requirements of ASME Code, Section III, Appendices G and H to 10 CFR Part 50, and 10 CFR 50.55a, which provide an acceptable basis for satisfying the requirements of GDC 1, 14, 30, 31, and 32.

5.3.2.4 Reactor Vessel Materials Surveillance Program

Appendix H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50 presents the requirements for a material surveillance program for operating reactors. The purpose of the material surveillance program is to monitor changes in the fracture toughness properties of ferritic materials in the RV beltline region which result from exposure of these materials to neutron irradiation. Material surveillance is accomplished using surveillance capsules which are holders of archival beltline material and fast neutron (E is greater than 1.0 million electron volts) dosimeters. Measurement of the irradiated material samples yields a measure of the embrittlement, and measurement of the dosimeter activation estimates the irradiation exposure.

RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," which is based on GDC 14, 30, and 31, describes methods and practices acceptable to the staff regarding calculational techniques and statistical practices using the dosimetry measurements. In addition, the results of the dosimetry are used to benchmark and validate calculational methods for estimating vessel irradiation.

In the DCD and its response to RAI 440.037, Revision 1, the applicant clarified its methods and practices regarding calculational techniques and statistical practices using the dosimetry measurements. These methods and practices are consistent with the guidance of RG 1.190. Therefore, the staff concludes that the AP1000 RV material surveillance program is acceptable. This is COL Action Item 5.3.2.4-1.

5.3.3 Pressure-Temperature Limits

The staff reviewed DCD Tier 2, Section 5.3.3, "Pressure-Temperature Limits," in accordance with SRP Section 5.3.2, "Pressure-Temperature Limits and Pressurized Thermal Shock." The applicant's P/T limit curves are acceptable if they meet codes and standards, and regulatory guidance commensurate with the safety function to be performed. This will ensure that the relevant requirements of 10 CFR 50.55a, "Codes and Standards, 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements," and GDC 1, 14, 31, and 32 are met. These requirements are discussed below.

- GDC 1 requires that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

- GDC 14 requires that the reactor coolant pressure shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

- GDC 31 requires that the RCPB shall be designed with sufficient margin to assure that, when stressed under operation, maintenance, testing, and postulated accident conditions, it will behave in a nonbrittle manner and minimize the probability of rapidly propagating fracture.

- GDC 32 requires that the RCPB components shall be designed to permit an appropriate material surveillance program for the reactor pressure vessel.

The NRC has established requirements in 10 CFR Part 50 to protect the integrity of the RCPB in nuclear power plants. The staff evaluates the P/T limit curves based on10 CFR Part 50, Appendix G; RG 1.99, Revision 2, and SRP Section 5.3.2.

Appendix G to 10 CFR Part 50 requires that P/T limit curves for the reactor pressure vessel (RPV) be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Code.

RG 1.99, Revision 2, contains methodologies for determining the increase in transition temperature and the decrease in USE resulting from neutron radiation. SRP Section 5.3.2 provides an acceptable method of determining the P/T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics methodology of Appendix G to Section XI of the ASME Code. The basic parameter of this methodology is the stress intensity factor, K_I, which is a function of the stress state and flaw configuration. Appendix G to the ASME Code requires a safety factor of 2.0 on stress intensities resulting from reactor pressure during normal and transient operating conditions; for hydrostatic testing curves, Appendix G to the ASME Code requires a safety factor of 1.5.

The methods of Appendix G to the ASME Code postulate the existence of a sharp surface flaw in the RPV that is normal to the direction of the maximum stress. This flaw is postulated to have a depth that is equal to one-quarter of the RPV beltline thickness, and a length equal to 1.5 times the RPV beltline thickness. The critical locations in the RPV beltline region for calculating heatup and cooldown P/T curves are the one-quarter thickness (1/4T) and three-quarters thickness (3/4T) locations, which correspond to the depth of the maximum postulated flaw, if initiated and grown from the inside and outside surfaces of the RPV, respectively.

Appendix G to the ASME Code, Section XI, methodology requires that applicants determine the adjusted reference temperature (ART or adjusted RT_{NDT}). The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin (M) term.

The ΔRT_{NDT} is a product of a chemistry factor (CF) and a fluence factor. The CF is dependent upon the amount of copper and nickel in the material, and may be determined from tables in RG 1.99, Revision 2, or from surveillance data. The fluence factor is dependent upon the neutron fluence at the maximum postulated flaw depth. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value, and whether the CF was determined using the tables in RG 1.99, Revision 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence and the calculational procedures. RG 1.99, Revision 2, describes the methodology to be used in calculating the margin term.

Appendix H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50 presents the requirements for a materials surveillance program to monitor the changes in fracture toughness properties of materials in the RV beltline region resulting from exposure to neutron irradiation and the thermal environment. These requirements include conformance with ASTM E-185-82. Compliance with Appendix H satisfies the requirements of GDC 32 regarding the provision of an appropriate materials surveillance program for the RV. The staff reviewed the RV materials to determine whether they meet the relevant requirements for Appendix H as they relate to determining and monitoring fracture toughness.

5.3.3.1 Summary of Technical Information

The AP1000 DCD for P/T limits indicates that the heatup and cooldown P/T limit curves are required as a means of protecting the RV during startup and shutdown to minimize the possibility of fast fracture. The methods outlined in Appendix G of Section XI of the ASME Code are employed in the analysis of protection against nonductile failure. Beltline material properties degrade with radiation exposure, and this degradation is measured in terms of the ART, which includes a reference nil ductility temperature shift, initial RT_{NDT}, and margin.

The predicted ΔRT_{NDT} values are derived considering the effects of fluence and copper and nickel content for the RV steels exposed to the reactor coolant at temperatures between 273.8 °C (525 °F) to 301.7 °C (575 °F). RG 1.99, Revision 2, is used to calculate the adjusted reference temperature. The heatup and cooldown curves are developed considering a sufficient magnitude of radiation embrittlement so that no unirradiated ferritic materials in other components of the RCS will be limiting in the analysis.

The applicant stated that the P/T curves are developed considering a radiation embrittlement of up to 54 EFPYs. This is consistent with an expected plant life of 60 years with 90 percent availability. The maximum limits for the copper and nickel elements of the RV are 0.03 percent copper and 0.85 percent nickel. The EOL RT_{NDT} will be determined for as-built material.

The operating curves are developed in accordance with 10 CFR Part 50, Appendix G, with the exception that the flange requirement is consistent with WCAP-15315, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Operating PWR and BWR [boiling water reactor] Plants." The curves are applicable up to 54 EFPYs. In DCD Tier 2, Figures 5.3-2 and 5.3-3, the applicant provided generic curves for the AP1000 RV design. These are limiting curves based on copper and nickel material composition.

The results of the material surveillance program will be used to verify the validity of ΔRT_{NDT} used in the calculation for the development of heatup and cooldown curves. The projected fluence, copper, and nickel contents, along with the RT_{NDT} calculation, will be adjusted, if necessary, from time to time using the surveillance capsules.

The applicant also indicated that temperature limits for core operation, inservice leak, and hydrotests are calculated in accordance with the ASME Code, Section XI, Appendix G.

5.3.3.2 Staff Evaluation

The staff reviewed the P/T limits for AP1000 in accordance with Section 5.3.2 of the SRP to ensure adequate safety margins for the structural integrity of the ferritic components of the RCPB.

The staff reviewed the P/T limits imposed on the AP1000 RV materials to ensure that the relevant requirements of GDC 1 and 10 CFR 50.55a(a)(1) have been met, as they relate to the selection of materials for the RV and their ability to ensure adequate safety margins for the structural integrity of the RCPB ferritic components. The SRP indicates that P/T limits established for the RCPB consistent with the requirements of 10 CFR Part 50, Appendix G, and to ASME Code, Section III, Appendix G ensure that the RCPB material fracture toughness requirements are satisfied. The applicant indicated that the temperature limits for core operation, inservice leak, and hydrotests are calculated in accordance with10 CFR Part 50, Appendix G, and ASME Code, Section XI, Appendix G. Therefore, the staff finds that the applicant's RCPB meets the appropriate quality standards of the ASME Code. Thus, the probability of the RCPB material failure, and the subsequent effects on reactor core cooling and confinement, are minimized. Therefore the staff finds that the applicant has adequately met the relevant requirements of GDC 1 and 10 CFR 50.55a(a)(1).

The staff reviewed the P/T limits imposed on the RV to ensure that the materials selected for the RV meet the relevant requirements of GDC 14, in that they possess adequate fracture toughness properties to resist rapidly propagating failure and to act in a nonbrittle manner. The applicant indicated that the P/T limit curves will be developed in accordance with the criteria of 10 CFR Part 50, Appendix G, thereby ensuring a low probability of significant degradation or gross failure of the RCPB that could cause a loss of reactor coolant inventory and a reduction in the capability to confine fission products.

The staff reviewed the RV materials to ensure that the relevant requirements of GDC 31 have been met as they relate to behavior in a nonbrittle manner and an extremely low probability of rapidly propagating fracture. In the DCD, the applicant indicated that RG 1.99, Revision 2, is used to calculate the ART. The staff requested that the applicant discuss the effects of temperature on embrittlement of RV materials, if a plant operates at a cold leg temperature below 273.8 °C (525 °F). The applicant, in its response dated October 18, 2002, indicated that the AP1000 cold leg temperature exceeds 273.8 °C (525 °F), and that the minimum steady state cold leg temperature is 279.4 °C (535 °F). This value corresponds to the conditions of 100 percent power, thermal design flow, and 10 percent tube plugging. Therefore the procedures of RG 1.99, Revision 2, for nominal embrittlement apply. The staff finds this acceptable because RG 1.99, Revision 2, provides methods for predicting the effects of radiation on fracture toughness properties that are applicable to the requirements of GDC 31. In addition, the staff reviewed the P/T limits that will be imposed on the RCPB during preservice hydrostatic tests, inservice leak and hydrostatic tests, heatup and cooldown operations, and core operation-criticality. The staff verified that adequate safety margins against nonductile behavior of rapidly propagating failure of ferritic components will exist, as required by GDC 31.

The staff reviewed the RV materials to ensure that the relevant requirements of GDC 32 have been met as they relate to the provision of a materials surveillance program. Compliance with 10 CFR Part 50, Appendix H, satisfies the requirements of GDC 32 regarding the provision of an appropriate materials surveillance program for the RV. The staff reviewed the RV materials to determine whether they meet the relevant requirements for Appendix H as they relate to determining and monitoring fracture toughness. Section 5.3.2, "Reactor Vessel Materials," of this report provides the staff's review of the material surveillance program.

The staff requested, in RAI 251.018, that the applicant demonstrate that the P/T limits are in accordance with Appendix G to 10 CFR Part 50. The applicant responded that the AP1000 heatup and cooldown operating curves were generated using the most limiting ART values and the NRC-approved methodology, as documented in WCAP-14040-NP-A, "Methodology Used to

Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," with staff-approved exceptions.

One exception is that instead of using best-estimate fluence values, the applicant is using calculated fluence values. The staff finds this acceptable because it complies with RG 1.190. Another exception is that the plane strain facture toughness (K_{Ic})critical stress intensities are used in place of the crack arrest facture toughness (K_{Ia}) critical stress intensities. This methodology is taken from the staff-approved ASME Code Case N-641. The staff found the applicant's responses to be acceptable because the AP1000 P/T limit curves were developed in accordance with 10 CFR Part 50, Appendix G, with the exception that the flange requirement is in accordance with WCAP-15315, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Operating PWR and BWR Plants." Currently, the staff has not approved WCAP-15315. Any changes to the RV closure head requirements would be incorporated into Appendix G to 10 CFR Part 50. If a relaxation to 10 CFR Part 50, Appendix G is approved, this will allow the operating window to be wider. Because applicants using the AP1000 are required to meet the requirements of 10 CFR Part 50, Appendix G, they must meet the closure head requirements of Appendix G to 10 CFR Part 50. However, the AP1000 DCD does not provide limitations (values of RT_{NDT}) for the closure flange region of the RV and head. The AP1000 design must include these limitations in order to satisfy Appendix G to 10 CFR Part 50. The applicant was asked to provide those limitations that are consistent with the present TS and 10 CFR Part 50, Appendix G, or provide closure flange limitations with new TS that are consistent with 10 CFR Part 50, Appendix G. This was Open Item 5.3.3-1.

By letter dated October 10, 2003, the applicant provided the revised sections of the AP1000 DCD, which also included revised P/T curves to address the reactor vessel closure head flange requirements of 10 CFR Part 50, Appendix G. The closure flange limitation is based on an RT_{NDT} of 10 °F, in accordance with DCD Tier 2, Table 5.3-3. The staff confirmed that the proposed curves are in accordance with 10 CFR Part 50, Appendix G for the closure flange. In addition, the applicant indicated that the RNS relief valve setpoint and capacity would also be revised as a result of a revised LTOP evaluation based on the new P/T curves. The staff found that the applicant adequately revised the appropriate sections of the AP1000 DCD to address the staff's open item with respect to the reactor vessel closure flange limitations. Therefore, the staff considers Open Item 5.3.3-1 to be closed because the applicant adequately meets the reactor vessel closure head flange requirements of 10 CFR Part 50, Appendix G.

As stated above, the applicant also provided revised P/T curves for the AP1000 design which are shown in DCD Tier 2, Figures 5.3-2 and 5.3-3. The applicant revised the DCD to indicate that these curves are generic curves for the AP1000 RV design. In addition, they are the limiting curves based on copper and nickel material composition. The applicant also indicated that the COL applicant will address the use of plant-specific curves during procurement of the RV. As noted in the bases to TS 3.4.14, the applicant indicated that use of plant-specific curves requires evaluation of the LTOP system. This includes evaluating the setpoint pressure for the normal RNS relief valve. Since TS will be developed by the applicant and reviewed by the staff, the applicant's LTOP setpoints will be reviewed at a later time. This is COL Action Item 5.2.2.2-1.

The staff requested, in RAI 251.017, that the applicant provide details for the P/T limit calculations, including their assumptions and margins. In response to RAI 251.017, the applicant provided the staff with details of the P/T limit calculations. The applicant indicated that it used the methodology of RG 1.99, Revision 2, to estimate the shift in reference temperature. The ART is the sum of the initial reference temperature for the material in the unirradiated condition, the shift in the reference temperature due to the irradiation of the material, and additional safety margins (margin values) to account for uncertainties in the RT_{NDT} measurements and calculation. The applicant indicated that the projected EOL fluence is 9.762×10^{19} neutrons/centimeter squared (n/cm^2) for the forging, and 2.847×10^{19} n/cm^2 for the lower girth weld. The applicant further indicated that the margin values at the 1/4T and 3/4T locations for the forging are 7.2 °C (45 °F) and 5.6 °C (42 °F), respectively. The margin values for the 1/4T and 3/4T locations of the lower girth weld are 18.9 °C (66 °F) and 10 °C (50 °F), respectively.

The AP1000 DCD provides the values of the copper and nickel composition and the initial RT_{NDT} values. The applicant calculated the adjusted reference temperature values to be 17.2 °C (63 °F) and 13.3 °C (56 °F) at the 1/4T and 3/4T locations of the forging, respectively, and 33.9 °C (93 °F) and 18.9 °C (66 °F) at the 1/4T and 3/4T locations of the lower girth weld, respectively. The staff independently verified that the applicant's predicted shifts in the reference temperature for the RV materials were calculated using the methodology of RG 1.99, Revision 2. This RG provides reasonably accurate and conservative predictions of adjusted reference temperatures for RV beltline materials that are produced domestically. The staff finds the applicant's approach acceptable for domestically produced steels.

However, the staff believes that steels from nondomestic sources could have different characteristic responses to radiation embrittlement, particularly those steels with high phosphorus and sulfur contents. The methodology of RG 1.99, Revision 2, may not apply to steels with high phosphorus and sulfur contents. The applicant indicated that regardless of the source of material, the RV beltline material would be maintained to ASME Code specifications. In addition, DCD Tier 2, Table 5.3-1, indicates that restrictive maximum content limits would be imposed on the critical residual elements (copper, nickel, phosphorus, etc.). The staff finds the applicant's approach acceptable because it is in compliance with the requirements of the ASME Code, and the chemical content controls imposed on the RV materials meet the guidelines for new plants, as specified in RG 1.99, Revision 2.

5.3.3.3 Conclusions

The staff concludes that the P/T limits imposed on the RCS for operating and testing conditions to ensure adequate safety margins against nonductile or rapidly propagating failure are in conformance with the fracture toughness criteria of Appendix G to 10 CFR Part 50. The change in fracture toughness properties of the RV beltline materials during operation will be determined through a material surveillance program developed in conformance with Appendix H to 10 CFR Part 50. The use of operating limits, as determined by the criteria defined in Section 5.3.2 of the SRP, provides reasonable assurance that nonductile or rapidly propagating failure will not occur. This constitutes an acceptable basis for satisfying the requirements of 10 CFR 50.55a, Appendix A to 10 CFR Part 50, and GDC 1, 14, 31, and 32.

5.3.4 Pressurized Thermal Shock

The staff reviewed DCD Tier 2, Section 5.3.4, as it applies to pressurized thermal shock (PTS), in accordance with SRP Section 5.3.2, "Pressure-Temperature Limits and Pressurized Thermal Shock." Title 10, Section 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," of the Code of Federal Regulations defines the fracture toughness requirements for protection against PTS events. This section also establishes the PTS screening criteria, below which no additional action is required for protection from PTS events. The screening criteria are given in terms of reference temperature (RT_{PTS}). These criteria are 148.9 °C (300 °F) for circumferential welds, and 132.2 °C (270 °F) for plates, forgings, and axial welds.

5.3.4.1 Summary of Technical Information

The applicant indicated that the evaluation of the AP1000 RV materials showed that even at the fluence level which results in the highest reference pressurized thermal shock temperature (RT_{PTS}) value, this value is well below the screening criteria of 132.2 °C (270 °F) for forgings, and 148.9 °C (300 °F) for circumferential welds, as presented in 10 CFR 50.61. The screening criteria will not be exceeded using the method of calculation prescribed by the PTS rule for the vessel design objective. DCD Tier 2, Tables 5.3-1 and 5.3-3 provide the material properties, initial RT_{NDT}, and EOL RT_{PTS} requirements and predictions. Materials exposed to high fluence levels at the beltline region of the RV are subject to the PTS rule.

5.3.4.2 Staff Evaluation

PTS events are potential transients in a pressurized-water RV that can cause severe overcooling of the vessel wall, followed by immediate repressurization. The thermal stresses, caused when the inside surface of the RV cools rapidly, combined with the high-pressure stresses, will increase the potential for fracture if a flaw is present in a low-toughness material. The materials most susceptible to PTS are the materials in the RV beltline where neutron radiation gradually embrittles the material over time.

The PTS rule established screening criteria to serve as a limiting level of RV material embrittlement beyond which operation cannot continue without further plant-specific evaluation. The screening criteria are given in terms of reference temperature, RT_{PTS}. The screening criteria are 132.2 °C (270 °F) for plates and axial welds, and 148.9 °C (300 °F) for circumferential welds. The RT_{PTS} is defined by the following equation:

$$RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS} + M$$

where:

$RT_{NDT(U)}$ = initial reference temperature

ΔRT_{PTS} = mean value in the adjustment in reference temperature caused by irradiation

M = margin to be added to cover uncertainties in the initial reference temperature, copper and nickel contents, fluence and calculational procedures

The applicant demonstrated that the AP1000 design meets the PTS screening criteria. The AP1000 reactor beltline design consists of two forgings and one circumferential weld. The AP1000 beltline forging material and weld metal will contain a maximum of 0.03 weight percent copper and 0.85 weight percent nickel. The initial RT_{NDT} is -23.3 °C (-10 °F) for the forging, and -28.8 °C (-20 °F) for the circumferential weld. In response to RAI 251.019, the applicant indicated that the maximum assumed neutron fluence is 9.7E19 n/cm^2 for the forgings, and 2.85E19 n/cm^2 for the circumferential weld at EOL (60 years). The margins, defined in 10 CFR 50.61, are 18.9 °C (34 °F) for the forgings, and 31.1 °C (56 °F) for the circumferential weld.

Using the above values, the staff determined that after 60 years of operation, the RT_{PTS} values for the forgings and circumferential weld will be 30 °C (54 °F) and 48.8 °C (88 °F), respectively, well below the PTS screening criteria.

5.3.4.3 Conclusions

The staff concludes that the AP1000 RV meets the relevant requirements of 10 CFR 50.61 because calculations show that the RV beltline materials will be substantially below the PTS screening criteria after 60 years of operation. The COL applicant will address verification of RT_{PTS} values based on plant-specific material properties and projected neutron fluences for the plant design objective of 60 years. This is COL Action Item 5.3.4.3-1.

5.3.5 Reactor Vessel Integrity

The staff reviewed DCD Tier 2, Section 5.3.4, "Reactor Vessel Integrity," in accordance with SRP Section 5.3.3, "Reactor Vessel Integrity." The applicant's assessment of RV integrity is acceptable if it meets codes and standards, and regulatory guidance commensurate with the safety function to be performed. This will ensure that the relevant requirements of 10 CFR 50.55a, "Codes and Standards"; 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events"; 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements"; 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements"; and GDC 1, 4, 14, 30, 31, and 32 are met. These requirements are discussed below.

- GDC 1, "Quality Standards and Records"; GDC 30, "Quality of Reactor Coolant Pressure Boundary," and 10 CFR 50.55a(a)(1) require that structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

- GDC 4, "Environmental and Dynamic Effects Design Bases," requires that SSCs important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.

- GDC 14, "Reactor Coolant Pressure Boundary," requires that the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

- GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," requires that the RCPB shall be designed with sufficient margin to assure that, when stressed under operation, maintenance, testing, and postulated accident conditions, it will behave in a nonbrittle manner and will minimize the probability of rapidly propagating fracture.

- GDC 32, "Inspection of Reactor Coolant Pressure Boundary," requires that the RCPB components shall be designed to permit an appropriate material surveillance program for the RPV.

Title 10, of the Code of Federal Regulations, Section 50.61, defines the fracture toughness requirements for protection against PTS events. This section also establishes the PTS screening criteria, below which no additional action is required for protection from PTS events.

- Appendix G, "Fracture Toughness Requirements," to 10 CFR Part 50 specifies the fracture toughness requirements for ferritic materials of the pressure-retaining components of the reactor coolant pressure boundary. The staff reviewed the RV materials as they relate to the materials testing and acceptance criteria for fracture toughness contained in Appendix G.

- Appendix H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50 presents the requirements for a material surveillance program to monitor the changes in fracture toughness properties of materials in the RV beltline region resulting from exposure to neutron irradiation and the thermal environment. These requirements include conformance with ASTM E-185, "Standard Recommended Practices for Surveillance Tests for Nuclear Reactor Vessels." Compliance with Appendix H satisfies the requirements of GDC 32 regarding the provision of an appropriate materials surveillance program for the RV. The staff reviewed the RV materials to determine that they meet the relevant requirements for Appendix H as they relate to determining and monitoring fracture toughness.

5.3.5.1 Summary of Technical Information

The applicant stated that the RV, including the closure head, is approximately 12.1 meters (40 feet) long, and has an inner diameter at the core region of 398.8 cm (157 in). Surfaces which can become wetted during operation and refueling are clad to a nominal 0.56 cm (0.22 in.) of thickness with stainless steel welded overlay which includes the upper shell top, but not the stud holes. The design objective for the AP1000 RV is to withstand the design environment of 17.34 MPa (2500 psi) and 343.3 °C (650 °F) for 60 years. The major factor affecting vessel life is radiation degradation of the lower shell.

As a safety precaution, no penetrations are made below the top of the core. The core is positioned as low as possible in the vessel to limit reflood time in an accident. To decrease outage time during refueling, access to the stud holes is provided to allow stud hole plugging with the head in place. The flange is designed to interface properly with a multiple stud tensioner device. By the use of a ring forging with an integral flange, the number of welds is minimized to decrease ISI time.

The vessel is manufactured from low-alloy steel plates and forgings to minimize size. The chemical content of the core region base material is specifically controlled. A surveillance program is used to monitor the radiation damage to the vessel material.

The RV is designed and fabricated in accordance with the quality standards set forth in 10 CFR Part 50, GDC 1 and 30, 10 CFR 50.55a, and the requirements of ASME Code, Section III. The vessel design and construction enables inspection in accordance with ASME Code, Section XI.

Cyclic loads are introduced by normal power changes, reactor trips, and startup and shutdown operations. These design-base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the design life. Thermal stratification during passive core cooling system operation and natural circulation cooldown is considered by performing a thermal/flow analysis using computational fluid dynamics techniques. This analysis includes thermally induced fluid buoyancy and heat transfer between the coolant and the metal of the vessel and internals. The analysis also uses thermal/flow boundary conditions based on an existing thermal/hydraulic transient analysis of the primary reactor coolant system.

The analysis verifies that the vessel is in compliance with the fatigue and stress limits of Section III of the ASME Code. The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The heatup and cooldown rates imposed by plant operating limits are 37.8 °C (100 °F) per hour for normal operations.

DCD Tier 2, Section 5.3.3, "Pressure-Temperature Limits," and the AP1000 TS provide the operating limitations for the RV. In addition to the analysis of the primary components discussed in DCD Tier 2, Section 3.9.1.4, "Considerations for the Evaluation of the Faulted Conditions," the RV is further qualified to ensure against unstable crack growth under faulted conditions. Safeguard actuation following a loss-of-coolant, tube rupture, or other similar emergency or faulted event, produces relatively high thermal stresses in regions of the RV that come into contact with water from the passive core cooling system. Primary consideration is given to these areas, including the RV beltline region and the RV primary coolant nozzles, to ensure the integrity of the RV under these severe postulated transients. TMI Action Item II.K.2.13, "Thermal-Mechanical Report on Effect of HPI [High Pressure Injection] on Vessel Integrity for Small-Break Loss-of-Coolant Accident with no AFW [Auxiliary Feedwater]," is satisfied upon submittal of RT_{NDT} values which are below the PTS rule screening values. Section 5.3.4 of this report further discusses PTS.

The internal surfaces of the RV are accessible for periodic inspection. Visual and/or nondestructive techniques are used. During refueling, the vessel cladding is capable of being inspected in certain areas of the upper shell above the primary coolant inlet nozzles, and if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

DCD Tier 2, Section 5.3.4.7, "Inservice Surveillance," provides further details of the applicant's inservice surveillance activities with regard to the components of the RV. Because radiation levels and remote underwater accessibility limit access to the RV, several steps, as indicated in the AP1000 DCD, have been incorporated into the design and manufacturing procedures in preparation for the periodic nondestructive tests which are required by the ISI requirements of the ASME Code.

The vessel design and construction enables inspection in accordance with ASME Code, Section XI. The RV ISI program is detailed in the TS.

5.3.5.2 Staff Evaluation

Although the staff reviewed most areas separately in accordance with the other SRP sections, the integrity of the vessel is of such importance that a special summary review of all factors relating to RV integrity was warranted. The staff reviewed the fracture toughness for the ferritic materials for the RV and the RCPB, the P/T limits for the operation of the RV, and the materials surveillance program for the RV beltline. Section 5.3.3 of the SRP provides the acceptance criteria and references that form the bases for this evaluation.

The staff reviewed the information in each area to ensure that inconsistencies did not exist that would reduce the certainty of vessel integrity. The areas reviewed and the sections of this report in which they are discussed are as follows:

- reactor coolant pressure boundary materials (Section 5.2.3)
- reactor coolant system pressure boundary ISI and testing (Section 5.2.4)
- reactor vessel materials (Section 5.3.2)
- pressure-temperature limits (Section 5.3.3)
- pressurized thermal shock (Section 5.3.4)

The integrity of the RV is ensured for the following reasons:

- The RV will be designed and fabricated to the high standards of quality required by the ASME Boiler and Pressure Vessel Code and the pertinent Code Cases.

- The RV will be fabricated from material of controlled and demonstrated quality.

- The RV will be subjected to extensive preservice inspection and testing to ensure that the vessel will not fail because of material or fabrication deficiencies.

- The RV will operate under conditions, procedures, and protective devices that ensure that the vessel design conditions will not be exceeded during normal reactor operation, maintenance, testing, and anticipated transients.

- The RV will be subjected to periodic inspection to demonstrate that its high initial quality of the RV has not deteriorated significantly under service conditions.
- The RV will be subjected to surveillance to account for neutron irradiation damage so that the operating limitation may be adjusted.
- The fracture toughness of the RV and RCPB materials will be sufficient to ensure that when stressed under operation, maintenance, testing, and postulated accident conditions, they will behave in a nonbrittle manner and will minimize the probability of rapidly propagating fracture.

5.3.5.3 Conclusions

The staff concludes that the structural integrity of the AP1000 RV meets the requirements of GDC 1, 4, 14, 30, 31, and 32 of Appendix A to 10 CFR Part 50; Appendices G and H to 10 CFR Part 50; 10 CFR 50.61; and 10 CFR 50.55a. Therefore, the staff finds the structural integrity of the AP1000 RV to be acceptable. The basis for this conclusion is that the design, materials, fabrication, inspection, and quality assurance requirements of the AP1000 plant will conform to the applicable NRC regulations and RG set forth above, as well as the rules of ASME Code, Section III. The fracture toughness requirements of the regulations and ASME Code, Section III, will be met, including requirements for surveillance of vessel material properties throughout its service life, in accordance with Appendix H to 10 CFR Part 50. In addition, operating limitations on temperature and pressure will be established for the plant in accordance with Appendix G, "Protection Against Nonductile Failure," of ASME Code, Section III, and Appendix G to 10 CFR Part 50.

5.4 Component and Subsystem Design

In DCD Tier 2, Section 5.4, "Component and Subsystem Design," the applicant described the design of RCS components and subsystems for the AP1000.

5.4.1 Reactor Coolant Pump Assembly

The AP1000 RCPs are single-stage, hermetically sealed, high-inertia, centrifugal, canned-motor pumps. There are a total of four RCPs, two in each SG. Two pumps, rotating in the same direction, are directly connected to the two outlet nozzles on the SG channel heads. The RCPs are designed to pump large volumes of reactor coolant at high pressures and temperature. High volumetric flow rates are needed to ensure adequate core heat transfer so as to maintain a departure from nucleate boiling ratio (DNBR) greater than the acceptable limit established in the safety analysis. Rotational inertia of a flywheel and other rotating parts in the pump assembly results in continuous coast-down flow after an RCP trip.

The RCP is an integral part of the RCPB. Section 5.2 of this report discusses the requirements on the integrity of RCPB. A canned-motor pump contains the motor and all rotating components inside a pressure vessel. The pressure vessel consists of the pump casing, thermal barrier, stator shell, and stator cap, which are designed for full RCS pressure. The stator and rotor are encased in corrosion-resistant cans that prevent contact of the rotor bars and stator windings with the reactor coolant. Because the shaft for the impeller and rotor is contained within the pressure boundary, seals are not required to restrict leakage out of the pump into containment. DCD Tier 2, Section 5.4.1.3.3, discusses the RCPB integrity of the RCPs. Section 5.4.1.4 of this report describes the staff's evaluation of the RCP for conformance to the RCPB requirements.

The RCP driving motor is a vertical, water-cooled, squirrel-cage induction motor with a canned rotor and a canned stator. It is designed for removal from the casing for inspection, maintenance, and replacement, if required. The motor is cooled by component cooling water circulating through a cooling jacket on the outside of the motor housing, and through a thermal barrier between the pump casing and the rest of the motor internals. Inside the cooling jacket are coils filled with circulating rotor cavity coolant. This rotor cavity coolant is a controlled volume of reactor coolant that circulates inside the rotor cavity.

Each pump motor is driven by a variable frequency drive, which is used only during heatup and cooldown when the reactor trip breakers are open. During power operations, the variable frequency drives is isolated and the pump are run at constant speed.

A flywheel, consisting of two separate assemblies, provides rotating inertia that increases the coast-down time for the pump.

5.4.1.1 <u>Pump Performance</u>

GDC 10 requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. For PWR designs, SRP Section 4.4 states that to meet the requirements of GDC 10, the hot rod in the core must not experience a departure from nucleate boiling, or the DNBR limit must not be violated, during normal operation or anticipated operational occurrences.

The RCP is sized to deliver a flow rate that equals or exceeds that required to ensure adequate thermal performance under normal and anticipated transient conditions. Adequacy of the RCP design capacity to deliver the forced reactor coolant flow and coast-down flow rates after an RCP trip is verified through the safety analyses of the design-basis transients to ensure that the DNBR limit is not violated during the transients. DCD Tier 2, Table 5.4-1, specifies the RCP design parameters; the design flow rate is 17,886 m^3/hr (78,750 gpm) per pump, the developed head is 111.25 m (365 ft), and the synchronous speed is 1,800 revolutions per minute (rpm). DCD Tier 2, Table 4.4-1, provides the thermal and hydraulic data for the AP1000 design; the vessel minimum measured flow rate is 68,516 m^3/hr (301,670 gpm), and the vessel thermal design flow rate is 67,229 m^3/hr (296,000 gpm), representing an uncertainty in the design and measurement flow of 1.9 percent. DCD Tier 2, Table 15.0-3, lists the nominal values of pertinent plant parameters utilized in the accident analyses. With the assumption of 10-percent SG tube plugging, the minimum measured and thermal design flow rates of 68,500 m^3/hr (301,600 gpm) and 67,229 m^3/hr (296,000 gpm), respectively, are used in the Chapter 15 safety analyses, with or without the revised thermal design procedure. AP1000 TS LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," requires the RCS flow to be greater than or equal to the minimum measured flow rate of, 68,516 m^3/hr (301,670 gpm) for Mode 1 power operation, with a surveillance verification every 12 hours, in accordance with TS SR 3.4.1.3. This will ensure that the RCS flow rate used in the DCD Tier 2, Chapter 15 transient and accident analyses are conservative with respect to the actual RCS flow rate delivered by the RCPs. The staff has reviewed the safety analyses of the design-basis events described in DCD Tier 2, Chapter 15. With the minimum measured flow rate of the reactor coolant as the initial condition, and the flow coastdown (see Section 5.4.1.2 of this report) after the reactor trip, the DNBR limit is not violated for all the anticipated transients analyzed. Therefore, GDC 10 is met. The staff concludes that the RCP design flow capacity is acceptable. The total delivery capability of the four RCPs will be verified using the inspections, tests, analyses, and acceptance criteria (ITAAC) described in DCD Tier 1, Table 2.1.2-4, Item 9.a.

The startup testing of the AP1000 contained in DCD Chapter 14, "Initial Test Program," requires the verification of adequacy of the RCS flow rate by (1) measurement prior to initial criticality, per Item 14.2.10.1.17, "Reactor Coolant System Flow Measurement," to verify the adequacy of the RCS flow rate for power operation, and (2) measurement at approximately 100-percent rated thermal power condition, per Item 14.2.10.4.11, "Reactor Coolant System Flow Measurement at Power Conditions," to verify that the RCS flow equals or exceeds the minimum value required by the plant TS. DCD Tier 2, Section 14.4.2, "Test Specifications and Procedures," requires the applicant to provide test specifications and test procedures for the preoperational and startup tests for review by the NRC. Therefore, the staff concludes that the AP1000 initial test program provides adequate verification of the total delivery capability of the RCP for adequate core cooling.

As stated in DCD Tier 2, Section 5.4.1.3.1, ample margin is provided between the available net positive suction head (NPSH) and the required NPSH to provide operational integrity and to minimize the potential for cavitation by conservative pump design and operation. The required NPSH is well within the operating RCS pressure during heatup, cooldown, and power operation with four pumps running. Because the available NPSH is always larger than the required NPSH, cavitation is not a concern.

5.4.1.2 <u>Coast-Down Capability</u>

For reactor fuel protection, each RCP has a high-density flywheel and high-inertia rotor. These provide rotating inertia to increase the pump's coast-down time following a pump trip and loss of electrical power. Continued coast-down flow of reactor coolant is important in ensuring that the fuel's DNBR limit will not be violated in the event of a partial or complete loss of the forced reactor coolant flow, as analyzed in DCD Tier 2, Chapter 15.3, "Decrease in Reactor Coolant System Flowrate." The ability of the RCP flywheel-rotor design to provide sufficient rotating inertia, and thus flow coast-down capability following an RCP trip, is verified through the safety analyses of the loss-of-flow transients which demonstrate that the minimum DNBR limit is not violated. The staff has reviewed the safety analyses of the design-basis transients for partial and complete loss of forced reactor flow, as described in DCD Tier 2, Sections 15.3.1 and 15.3.2, respectively. The RCP coast-down flow rate is calculated on the basis of an RCP rotating moment of inertia of 695.3 kg-m^2 (16,500 lb-ft^2), which is specified in DCD Tier 2,

Table 5.4-1, using the LOFTRAN computer code. The staff has approved this computer code for the AP1000 transient analyses, as discussed in Section 21.6.1 of this report. The analysis results for partial and complete loss of forced reactor coolant flow demonstrate that with coastdown of the affected pumps, the DNBR does not decrease below the design-basis limit value at any time during the transients. Therefore, the staff concludes that the RCP flywheel design provides adequate flow coast-down capability.

The acceptance criteria specified in DCD Tier 1, Table 2.1.2-4, Item 8b, for the calculated rotating moment of inertia for each RCP is no less than 695.3 kg-m^2 (16,500 lb-ft^2). Therefore, based on the above evaluation, the staff finds the RCP coast-down capability to be acceptable.

5.4.1.3 Rotor Seizure

In DCD Tier 2, Section 5.4.1.3.6.2, the applicant stated that the design of the AP1000 RCP (and motor) precludes the instantaneous stopping of any rotating component of the pump or motor. However, DCD Tier 2, Section 15.3.3, "Reactor Coolant Pump Shaft Seizure (Locked Rotor)," presents a design-basis analysis of a postulated RCP rotor seizure. The analysis of thermal and hydraulic effects of the locked rotor event uses a nonmechanistic, instantaneous stop of the impeller. This conservative assumption bounds any slower stop. The transient analysis considers the effect of the locked rotor on the reactor core and the RCS pressure to demonstrate that acceptable RV pressure boundary and radiological consequence limits are not exceeded. The staff reviewed the analysis of the pump rotor seizure event as part of the Chapter 15 design-basis analysis and found the results to be acceptable, as discussed in Section 15.3.2 of this report.

5.4.1.4 Reactor Coolant Pump Flywheel Integrity

The following regulatory requirements are applicable to the designs of the RCP flywheels for the AP1000 reactors:

- 10 CFR 50.55a(a)(1) and GDC 1 of Appendix A to 10 CFR Part 50 both require that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.

- GDC 4 in Appendix A to 10 CFR Part 50 requires that SSCs important to safety shall be protected against the dynamic effects, including missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power plant unit.

5.4.1.4.1 Summary of Technical Information

DCD Tier 2, Section 5.4.1.3.6.3, provides the detailed technical description of the AP1000 RCP flywheel design. In this section of the design certification document, the applicant stated that each RCP for the AP1000 reactor is designed with a high-density flywheel and high-inertia rotor. These components provide the RCP with a continual coast-down capability following an RCP trip. The applicant also stated that to ensure this coast-down capability, the RCP rotor must be designed against a sudden seizure. The RCP flywheel is also analyzed to demonstrate that the integrity of the pressure boundary components will be maintained in the event of a postulated RCP flywheel missile.

5.4.1.4.2 Staff Evaluation

The RCP flywheels for the AP1000 are designed to provide the RCP with the ability to safely coast down from an RCP overspeed condition, without a rupture of the RCP rotor resulting. The applicant described the design features of the AP1000 RCP flywheels in DCD Tier 2, Section 5.4.1.3.6.3, and WCAP-15994-P, Revision 0, "Structural Analysis for the AP1000 Reactor Coolant Pump High Inertia Flywheel." This report addresses the fabrication, design, and structural integrity of the AP1000 RCP flywheel. The staff reviewed the information in DCD Tier 2, Section 5.4.1.3.6.3, and WCAP-15994-P, Revisions 0 and 1, to assess the AP1000 RCP flywheel design, and whether the design had the potential to impact the structural integrity of the RCPB. Section 5.4.1.3 of this report describes the staff's evaluation of the RCP rotors for protection against seizure.

During the staff's review of the AP600 design certification, the staff asked the applicant (AP600 RAIs 251.2 through 251.23) to address questions on design aspects, materials of fabrication, fabrication practices, and structural integrity analyses used for the design of the AP600 RCP flywheels. In RAI 251.21 for AP1000, the staff requested confirmation that WCAP-13474 and WCAP-13575 were still applicable to the design of the AP1000 RCP flywheels. In RAI 251.21, the staff also requested the applicant to confirm that its previous responses to AP600 RAIs 251.2 through 251.23 were applicable to the AP1000 RCP flywheel design. If not, the staff asked the applicant to provide updated information to address the responses to AP600 RAIs 251.2 though 251.23 as they relate to the design of the AP1000 RCP flywheels and the structural integrity of the RCPB, in the event of a postulated AP1000 RCP flywheel failure.

In response to RAI 251.21 for AP1000, the applicant provided updated responses to the AP600 RAIs 251.2 through 251.23, as relevant to the design aspects, materials of fabrication, fabrication practices, stress analyses, and missile generation analyses used for the design of AP1000 RCP flywheels and its assemblies. In addition, the applicant submitted Proprietary Class 2 Topical Report WCAP-15994-P, Revision 0, and indicated that the information in this report supercedes the information in WCAP-13474 and WCAP-13575, and updates the design information for the AP1000 RCP flywheels. The applicant submitted WCAP-15994-P, Revision 1, to update and clarify some of the design aspects of the RCP flywheel enclosure welds. The staff reviewed WCAP-15994-P, Revision 1, to assess the design aspects of the AP1000 RCP flywheel.

The AP1000 RCP flywheel assembly is fabricated from a high-quality, depleted uranium-molybdenum (U-2Mo) alloy casting. The uranium flywheel castings are made by a centrifugal casting process that minimizes casting defects. The flywheel is subjected to preservice volumetric and surface examinations. There is a lack of data regarding the fracture toughness of the uranium alloy used to fabricate the AP1000 RCP flywheel material. The lack of fracture toughness data for the depleted uranium alloy used in the design potentially diminishes the reliability aspect of the AP1000 RCP flywheel design. Therefore, the AP1000 RCP flywheel design basis is not predicated on precluding a stress-induced or fatigue-induced failure of the flywheel. Rather, the AP1000 RCP flywheel design is based on the limiting, postulated AP1000

RCP flywheel missile fragment not having sufficient kinetic energy to penetrate the RCPB components associated with the RCP (i.e., RCP casing, stator shell/flange, and thermal barrier). Therefore, the potential for diminished fracture toughness reliability is not a factor in the staff's assessment of the AP1000 RCP flywheel design.

The AP1000 RCP flywheels are located within an enclosure fabricated from Alloy 690. In contrast, the AP600 RCP flywheel enclosures were fabricated from Alloy 600. Alloy 690 should provide the AP1000 RCP flywheel enclosure with additional corrosion resistance. The staff considers this to be an improvement in the design of the AP1000 RCP flywheel enclosure.

The Alloy 690 enclosure is located within the RCP stator shell/flange and thermal barrier, which serve as part of the pressure boundary for the RCP. The flywheel enclosure is a welded design that is similar to the design used for the applicant's other motor rotor designs. The flywheel enclosure isolates the RCP flywheel from exposure to the reactor coolant. The RCP flywheel enclosure is credited with minimizing the potential for corrosion of the flywheel and contamination of the reactor coolant by depleted uranium. However, the enclosure is not credited with retention of missile fragments that could potentially result from a postulated failure of the flywheel disc. No industry experience demonstrates that the RCP flywheel enclosure is susceptible to fast-fracture-induced or fatigue-induced failures.

The applicant's RCP flywheel design is fabricated from an alternative material and does not entirely conform to the guidelines in RG 1.14, "Reactor Coolant Pump Flywheel Integrity," Revision 1. However, to meet the intent of RG 1.14, Revision 1, the applicant has performed the following three structural analyses for the AP1000 RCP flywheel designs:

- an analysis to evaluate the failure by ductile fracture of the uranium alloy RCP flywheel inserts (discs) using the faulted stress limits found in ASME Code, Section III, Appendix F.
- a structural analysis of the flywheel enclosure under normal operating and design speeds (1800 rpm and 2250 rpm, respectively) using the ASME Code, Section III, Subsection NG limits
- a kinetic energy assessment of the limiting RCP flywheel fragment that is postulated to occur with a failure of a flywheel disc (i.e., a RCPB safety analysis)

The applicant also performed a ductile failure analysis of the RCP flywheel discs under rotational loading associated with normal operation (1800 rpm) and design overspeed operation (2250 rpm). Based on the analysis presented in WCAP-15994-P, Revision 1, the applicant has demonstrated that the primary stresses for the depleted uranium alloy discs are less than the stress limits under normal and design operating conditions. Therefore, the staff finds them to be acceptable.

AP1000 RAI 251.21 was predicated, in part, on verifying that the proper stresses associated with a limiting design-basis accident of the AP1000 main coolant loop piping would be included as part of the applicant's ductile failure analysis for the RCP flywheel under design overspeed conditions. The applicant, as part of its response to AP1000 RAI 251.21 (and its response to AP600 RAI 251.8, as given in the attachment relative to the AP1000 RCP flywheel design), clarified that the AP1000 RCS coolant piping size of 6-inch nominal pipe size (NPS) or larger is qualified for leak before break. Therefore, the stresses associated with the largest RCS pipe break analyzed for the flywheel integrity for a LOCA associated with a 4-inch NPS RCS pipe break. This provides additional information that clarifies the limiting stresses that the applicant analyzed for the structural integrity assessment of the AP1000 RCP flywheel. Based on an acceptable review of AP1000 DCD Tier 2, Section 3.6.3, and DCD Tier 2, Appendix 3B on leak before break, the applicant has demonstrated that the stresses associated with a postulated LOCA for pipe sizes greater than 4-inch NPS need not be incorporated as inputs into the structural integrity assessments for the AP1000 RCP flywheels.

The applicant performed a structural analysis of the outer flywheel enclosure under both steady-state conditions (i.e., normal operating speeds at 1800 rpm) and design overspeed conditions (125 percent of normal operating speeds). The applicant's structural analyses for the flywheel enclosure under steady-state and design overspeed conditions were based on appropriate mechanical and thermal loading (stress) data. The applicant's analyses of the flywheel enclosure indicate that the stresses associated with the enclosure for both normal operating and design conditions are less than the allowable stress limits of the Alloy 690 material used to fabricate the enclosure. This analysis demonstrates that the outer flywheel enclosures will not yield (plastically deform) under normal and design overspeed operations of the RCP flywheel. The applicant did not perform a stress analysis of the outer flywheel enclosure under critical overspeed conditions. The staff finds this acceptable because the applicant does not credit the flywheel enclosure with preventing a postulated flywheel fragment from reaching the pressure boundary components associated with the RCP.

The safety analysis for the AP1000 RCP flywheel design was evaluated in terms of whether or not the kinetic energy associated with a postulated failure of the limiting flywheel disc is capable of penetrating the pressure boundary components associated with the AP1000 RCP (i.e., the RCP casing, stator shell/flange, and thermal barrier). These pressure boundary components contain the RCP flywheel disc whose failure could generate a limiting flywheel fragment. The limiting RCP flywheel disc and the pressure boundary components associated with the RCP were analyzed to demonstrate that a failure of the flywheel would not penetrate the RCPB, even in the event of a postulated generation of a limiting RCP flywheel missile and breach of the RCP flywheel enclosure. The theoretical worst-case flywheel failure analysis is analogous to the approach taken in the theoretical worst-case turbine disc failure analysis. The applicant has demonstrated, in WCAP-15994-P, Revision 1, that the highest amount of energy associated with an RCP flywheel missile constitutes only a small fraction (less than 15 percent) of the kinetic energy that would be required to penetrate the pressure boundary components associated with the RCP. This analysis provides an acceptable basis for not including the AP1000 RCP flywheels and their enclosures under an ISI program, as recommended by RG 1.14, Revision 1.

Because the applicant's safety analysis has demonstrated that a postulated RCP flywheel failure is not capable of penetrating the RCPB and will not result in a missile that could have adverse effects on the plant's safety functions, the staff concludes that the requirement for an ISI program to preclude such failures is unnecessary from a safety standpoint.

5.4.1.4.3 Conclusions

The staff has reviewed the information in DCD Tier 2, Section 5.4.1.3.6.3, WCAP-15994-P, Revisions 0 and 1, and the applicant's response to AP1000 RAIs 251.20 and 251.21, as related to the applicant's design of the AP1000 RCP flywheels. On the basis of this review and the applicant's acceptable conclusions on LBB described in Section 3.6.3 of this report, the staff concludes that the applicant has demonstrated that the AP1000 RCP flywheels and their enclosures have been designed appropriately, considering the use of acceptable materials and fabrication processes. In addition, the staff finds that the integrity of the RCP pressure boundary will be maintained in the event of a postulated RCP flywheel missile. Based on this review, the staff concludes that the measures taken to ensure the integrity of the RCP flywheels are acceptable and meet the safety requirements of GDC 1 and 4 and 10 CFR 50.55a(a)(1).

5.4.2 Steam Generators

The AP1000 design has two vertical-shell, U-tube Model Delta 125 steam generators. The basic function of these SGs is to transfer heat from the primary reactor coolant through the U-shaped heat exchanger tubes to the secondary side of steam generation. The design of the Model Delta 125 SGs, except for the configuration of the channel head, is similar to an upgraded Model Delta 75 SG, which have been placed in operation as replacement steam generators. In the channel head under the SG tube sheet, a divider plate is used to separate the inlet and outlet chambers. Two canned-motor RCPs are directly attached to the cold leg nozzles on the outlet channel head to provide the driving force for the reactor coolant flow. A PRHR nozzle is attached to the bottom of the channel head of the loop 1 SG on the cold leg portion of the head. This nozzle provides recirculated flow from the PRHR HX, which cools the primary side under emergency conditions.

The SG channel head, tube sheet, and tubes are a portion of the RCPB, and are designed to satisfy the criteria specified for Class 1 components. The tubes transfer heat to the secondary (steam) system, while retaining radioactive contaminants in the primary system.

The SGs remove heat from the RCS during power operation, anticipated transients, and under natural circulation conditions. The heat transfer function of the SGs, and associated secondary water and steam systems, are not required to provide a safety-grade safe shutdown of the AP1000. Safe shutdown is achieved and maintained by the safety-related passive core cooling systems.

For the SG operation, the reactor coolant flow from the RCS hot leg enters the primary side of the inverted U-tubes, transferring heat to the secondary side during its traverse. The flow then returns to the cold leg side of the primary chamber, exits the SG via two cold leg nozzles and the canned RCPs, and enters the RV, thus completing a cycle.

If the PRHR system is activated, flow passes from the outlet of the PRHR HX, through the SG PRHR nozzle connection, and into the SG channel head. Coolant then flows through the RCPs, into the cold legs, and then into the RV.

On the secondary side, feedwater enters the SG at an elevation above the top of the U-tubes through a feedwater nozzle. The feedwater enters a feedring via a welded thermal sleeve connection, and exits through nozzles attached to the top of the feedring. This nozzle design minimizes the potential for trapping pockets of steam that can lead to water hammer in the feedwater piping by discharging feedwater into the SG at an elevation above the top of the tube bundle and below the normal water level, thus reducing the potential for vapor formation in the feedring. After exiting the nozzles, the feedwater mixes with saturated water that has been mechanically separated from the steam flow exiting the SG by internal moisture separators. The combined feedwater/recirculation flow then enters the downcomer annulus between the tube wrapper and the shell. At the bottom of the tube wrapper, the water is directed toward the center of the tube bundle by the lowest tube support plate. This recirculation arrangement is designed to minimize low-velocity zones, which present the potential for sludge deposition. As the water passes the tube bundle, it is converted to a steam-water mixture, which subsequently rises into the steam drum section. Centrifugal moisture separators then remove most of the entrained water from the steam. The steam continues to the secondary moisture separators, or dryers, for further moisture removal, increasing its quality to a designed minimum of 99.75 percent (0.25 percent by weight maximum moisture). Water separated from the steam combines with entering feedwater and recirculates through the SG. Dry steam exits the SG through the SG outlet nozzle, which has an installed steam-flow restrictor.

The startup feedwater system (SUFS) supplies water to the SGs during startup, shutdown, and other times when the normal feedwater system is not needed or not operable. The SUFS is a non-safety grade system that will be used as a defense-in-depth system following a reactor trip or loss of main feedwater event. The SUFS thus provides investment protection for the plant. During startup and shutdown operations, the SG has enough surface area, and a small enough primary-side hydraulic resistance, to remove decay heat from the RCS by natural circulation (without operation of the RCPs).

DCD Tier 2, Tables 5.4-4 and 5.4-5, respectively, detail the SG design requirements and design parameters. The evaluation of SG thermal performance, including required heat transfer area and steam flow, uses conservative assumptions for parameters such as primary flow rates and heat transfer coefficients. The effective heat transfer coefficient is determined by the physical characteristics of the AP1000 SG and the fluid conditions in the primary and secondary systems for the nominal 100-percent design case. It includes a conservative allowance for fouling and uncertainty.

As stated above, the SG heat transfer function is not required for safe shutdown. Because the secondary systems, such as the normal feedwater system and the SUFS are not safety-related systems, they cannot be credited in the SG heat transfer function for mitigation of transients and accidents in the design-basis analyses. The staff reviewed and confirmed that no credit of these non-safety-related systems is taken in the analyses of the design-basis transients and accidents in Chapter 15 of the DCD. However, in the evaluation of non-design-basis, multiple SG tube rupture (MSGTR) events using realistic calculations, the heat transfer function, as well as other accident-mitigating characteristics of the SG, may be considered. Section 5.4.2.3 of this report discusses the MSGTR/containment bypass issue.

5.4.2.1 Steam Generator Materials

The staff reviewed DCD Tier 2, Section 5.4.2.4, "Steam Generator Materials," in accordance with Section 5.4.2.1, "Steam Generator Materials," of the SRP to ensure that this portion of the RCPB is maintained. The materials used in the fabrication of the SGs are acceptable if the following GDC are met:

- GDC 1 and 10 CFR 50.55a(a)(1) require that structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed.
- GDC 14 requires that the steam generator shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.
- GDC 15 requires that the steam generator shall be designed with sufficient margin to assure that design conditions of the reactor coolant boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.
- GDC 31 requires that the steam generator shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions, it will behave in a nonbrittle manner and minimize the probability of rapidly propagating fracture.

5.4.2.1.1 Summary of Technical Information

The AP1000 SG is designed to the ASME Code with the pressure-retaining parts of the SG, including the primary and secondary pressure boundaries, designated as Class 1, and the secondary side of the SG designated as Class 2.

The pressure boundary materials used in the SG are selected and fabricated in accordance with the requirements of ASME Code, Sections II and III. The AP1000 design includes the use of Alloy 690, a Ni-Cr-Fe alloy (ASME SB-163) for the SG tubes. In addition, the channel head divider plate is made with Alloy 690 (ASME SB-168). The interior surfaces of the reactor coolant channel head, nozzles, and manways are clad with austenitic stainless steel, while the primary side of the tube sheet is weld clad with Ni-Cr-Fe alloy (ASME SFA-5.14). The SG tubes are seal-welded to the tube sheet cladding and comply with the ASME Code, Sections II and III. The welds are dye penetrant inspected and leak-tested before each tube is hydraulically expanded the full depth of the tube sheet bore. Ni-Cr-Fe alloys are used in areas where high velocities could lead to erosion corrosion (e.g., feedwater ring, feedwater sparger, and some primary separator parts). The heat and lot of tubing material for each SG tube are recorded and documented. In addition, archive samples are available to the COL applicant for use in future materials testing programs or as ISI calibration standards.

To minimize crevice areas and deposition of contaminants, the following are considered in the design of the AP1000 SG:

- The portion of the tube within the tube sheet is expanded hydraulically to close the crevice between the tube and tube sheet.
- The SG tubes are supported by either an open lattice design (egg crate) or by a support plate. The support plates are made of Type 405 stainless steel alloy with a three-lobed (trifoil) tube hole design to provide flow adjacent to the tube outer surface.
- Antivibration bars are made from wide strips of Type 405 stainless steel to assist in the vibrational stability of the tube bundle.
- Wrapper design results in significant water velocities across the tube sheet to minimize dryout and sludge accumulation.
- Blowdown intake is at the periphery and is capable of continuous blowdown at a moderate volume and intermittent flow.
- A passive sludge collector (mud drum) provides a low-flow settling zone and can be cleaned during plant shutdown.
- Four 15.2–cm (6-inch) access ports are available for sludge lancing, which is a method for cleaning the SG in which a hydraulic jet inserted through the access ports loosens deposits and flushes them out of the SG. These ports can also be used for inspection of the tube bundle and retrieval of loose objects. In addition, two 10.2-cm (4-inch) ports are located on the secondary shell to provide access to the U-bend area of the tube bundle.

Corrosion tests performed on Alloy 690 TT ASME SB-163 have simulated the effects of SG water chemistry on the tubes. Test results indicate that the loss of material due to general corrosion over the 60-year operating design objective is small compared to the tube wall thickness. In addition, tests have shown that the Alloy 690 TT provides as good or better corrosion resistance than Alloy 600 TT or Ni-Cr-Fe Alloy 800 in caustic and chloride aqueous solutions.

Laboratory tests also show that the Alloy 690 TT tubing is compatible with the all-volatile treatment environment (i.e., a treatment program to minimize the possibility of tube wall thinning and intergranular corrosion in localized areas due to excessive levels of free caustic). Secondary side materials used in the AP1000 design are compatible with the secondary water chemistry.

5.4.2.1.2 Staff Evaluation

The staff reviewed DCD Tier 2, Section 5.4.2.4, "Steam Generator Materials," in accordance with Section 5.4.2.1, "Steam Generator Materials," of the SRP to ensure that the integrity of the SG materials is maintained, and that the SG materials meet the requirements of GDC 1, 14, 15, and 31, and Appendix B to 10 CFR Part 50.

Selection and Fabrication of Materials. The staff reviewed the materials selected (e.g., austenitic and ferritic stainless steels, ferritic low-alloy steels, carbon steels, and high nickel alloys) for the SG in terms of their adequacy, suitability, and compliance with ASME Code, Sections II and III. The requirements of GDC 1 are met for materials specifications by complying with the ASME Code. The requirements of the Code cases are fulfilled by meeting the appropriate provisions in RG1.84. The fracture toughness requirements of GDC 14 and 31 for Class 1 ferritic materials are met by satisfying the requirements of Appendix G to 10 CFR Part 50, and the requirements of ASME Code, Section III, Subarticle NB-2300, and Appendix G, Article G-2000. The fracture toughness requirements of GDC 14 and 31 for Class 2 ferritic materials are met by satisfying the requirements of ASME Code Section III, Subarticle NC-2300.

The staff reviewed the materials selected for the SG and concludes that the materials are acceptable because they meet the requirements/guidance of the ASME Code, Sections II and III, and RG 1.84.

The staff reviewed the AP1000 SG welding qualification, weld fabrication processes, and inspection during fabrication and assembly and concluded that they conform to the requirements of ASME Code, Sections III and IX. In addition, the welds between the tube and the tube sheet conform to the requirements of ASME Code, Sections III and IX.

The staff reviewed the tube material and its heat treatment and concludes that the thermally treated tubes are acceptable because of the improved corrosion resistance observed in currently operating SGs.

Based on their compliance with code requirements and RG 1.84, as well as the use of thermally treated tubing, the staff finds that the materials and fabrication processes used for the AP1000 SG design are acceptable and meet GDC 1.

The staff reviewed the fracture toughness of the RCPB materials and concludes that they meet the requirements of Appendix G to 10 CFR Part 50 and the requirements of ASME Code, Section II, Subarticle NB-2300, and Section III, Appendix G. In addition, the staff reviewed the fracture toughness of the Class 2 components of the SG and concluded they meet the requirements of ASME Code, Section III, Subarticle NC-2300. Therefore, the staff finds that the AP1000 SG design satisfies the fracture toughness requirements of GDC 14 and 31.

Steam Generator Design. The staff reviewed the design and fabrication of the SG to determine the extent to which crevice areas are minimized and whether sufficient corrosion allowance exists. The requirements of GDC 15 are met, in part, by designing the SG to avoid crevice areas and to promote high-velocity flow along the tubes to minimize buildup of corrosion products, and by meeting the appropriate provisions of ASME Code, Section III.

The staff reviewed the design and fabrication of the SGs to determine the extent to which crevice areas are minimized. The staff notes that the AP1000 design includes features that minimize or eliminate the crevice areas that resulted in corrosion issues with earlier SG designs. Specifically, the AP1000 design expands the tubes into the tube sheet for the entire length of the tube sheet and uses trifoil broached hole tube support plates.

The staff requested, in RAI 252.006, that the applicant clarify which tube support plate design will be used in the AP1000 (i.e., open lattice (egg crate) or broached hole), because the discussion in DCD Tier 2, Section 5.4.2.3.3, "Mechanical and Flow-Induced Vibration under Normal Operating Conditions," only discusses the broached hole tube support plate design. In its response, the applicant stated that the open lattice design is mentioned as a possible option for the tube support design; however, the design descriptions and evaluations in DCD Tier 2, Section 5.4.2.3.3, are based on the broached hole support plate design only. The staff reviewed this response and determined that if the open lattice (egg crate) tube support plate design is an option for the AP1000 design, then the SG design descriptions and evaluations in DCD Tier 2, Section 5.4.2.3.3, must be expanded to include this alternative design for the staff's approval. The staff reviewed the revised DCD and found that the applicant had removed references to the open lattice (egg crate) tube support plate design as an option. Based on this revision, the staff finds the discussions of the tube support plate design in the DCD to be acceptable.

The staff requested, in RAI 251.022, the applicant to provide the results of the flow-induced vibration (FIV) tests and calculations on the SGs, with special emphasis on fluid-elastic vibration. In addition, the staff requested the criteria for establishing the instability threshold for ensuring that fluid-elastic behavior does not contribute unacceptably to FIV or alternating stresses. In its response, the applicant stated that the FIV analysis for the AP1000 SG is not complete; however, evaluation of the tube bundle designs for the Delta-109 and Delta-75 SGs have been performed. The Delta-109 tube bundle has a similar tube bundle configuration, including tube size and tube bundle diameter, as the AP1000 SG. Extensive testing and evaluation of the tube bundle designs for the applicant SGs have been performed using analytical models to evaluate tube vibration. These results have been validated with a number of flow tests using various tube sizes and pitch geometries. The two regions of interest in the evaluation of FIV in SG tubes are the inlet area at the bottom of the tube bundle and the U-bend region at the top of the tube bundle.

In a followup question to RAI 251.022, the staff requested the applicant to provide the basis for the 0.75 fluid-elastic stability ratio criterion, and describe whether "time domain" analyses had been performed demonstrating that stresses associated with the criterion are negligible. The applicant's response did not address the staff's question. The staff's understanding of the applicant's response is that the 0.75 factor is based on judgment rather than being selected to address any specific uncertainty or time domain analysis. However, the applicant did not explain the rationale by which this judgment was reached. Furthermore, the applicant stated that time-domain analyses, which include direct consideration of alternating stress and fatigue, have been performed in some cases and have sometimes led to U-bend support systems with more margin than is required to meet the 0.75 fluid-elastic stability ratio criterion. To reiterate, the staff requested the rationale for assuming that the alternating stress and associated fatigue usage induced by fluid-elastic coupling is negligible for the case in which the fluid-elastic stability ratio is 0.75. This was Open Item 5.4.2-1 in the DSER.

By letter dated July 3, 2003, Westinghouse stated that the design stability ratio criterion of 0.75 is based on judgment and is intended to bound the onset of instability due to uncertainties in the analytically derived flow fields, mathematical models of the tube/support system, and material properties. Conservative instability constants and damping values are employed such that the stability ratio criterion need not be adjusted to reflect uncertainties in these parameters. Assuming ideal pinning of the tubes at the tube support plates, tube response is driven entirely by turbulence and vortex shedding when below the fluid-elastic instability threshold. Westinghouse analytical models conservatively bound the turbulence and vortex shedding response.

Westinghouse noted that actual SG tube supports are not ideal pinned supports. Nominally, these supports have widths and clearances that permit a range of possible tube/support interaction conditions. Among the possibilities is that the tube may initially respond to the flow field within the clearances as if one or more of the supports is not present. Thus, the tube could begin to respond to turbulence, vortex shedding, or fluid-elastic excitation earlier than would be expected from a model which assumes ideally pinned supports until the magnitude of vibration causes intermittent interaction with the support across the clearance. Westinghouse stated that some early model steam generators experienced moderate tube wear in the u-bends resulting from fluid-elastic rattling within loosely fitting AVB supports. Westinghouse considers the alternating stresses from vibration from within tube supports as part of its fatigue analyses.

The opposite extreme to loose supports are supports that become effectively clamped as a result of a buildup of deposits in the clearance region or denting. Such a condition can lead to fluid-elastic excitation earlier than would be expected from a model that assumes pinned supports. The 0.75 stability ratio criterion is not intended to address such off nominal conditions. Instead, Westinghouse considers a range of support assumptions and corresponding damping models in its analyses.

Based on the above, the staff concludes that Westinghouse has provided an adequate description of the basis for the 0.75 stability ratio design criterion and the context of its usage. Therefore, Open Item 5.4.2-1 is resolved.

Compatibility of the Steam Generator Components with the Primary and Secondary Coolant. The design and fabrication of the SG is reviewed to ensure compatibility of austenitic and ferritic stainless steels, ferritic low-alloy steels, carbon steels, and high-nickel alloys with the primary and secondary coolants. The requirements of GDC 14 are met through proper maintenance of primary and secondary water chemistry to ensure the integrity of the barrier between primary and secondary fluids.

The staff reviewed the compatibility of austenitic and ferritic stainless steels, ferritic low-alloy steels, and carbon steels with the primary and secondary coolants. The AP1000 design includes primary and secondary water chemistry guidelines discussed and evaluated in Sections 9.3.3, "Primary Sampling System," and 9.3.4, "Secondary Sampling System," of this report. When used in plant operations, these guidelines reduce the possibility of SCC, denting, pitting, and wastage of SG tubes through chemistry controls. Therefore, the staff finds the AP1000 design acceptable in ensuring the compatibility of the SG components with the primary and secondary coolant. Thus, the staff finds that the AP1000 design meets the requirements of GDC 14.

Cleanup of Secondary Side. The design and fabrication of the SG is reviewed to ensure access for removing surface deposits, sludge, and corrosion products which supplement the removal of sludge during blowdown. The requirements of GDC 14 are met by satisfying RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and ANSI N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants."

The staff reviewed the AP1000 design to verify access to the SG for removal of surface deposits, sludge, and corrosion products. These design features supplement sludge removal during blowdown of the SG. The staff finds that the AP1000 design is acceptable because it includes access ports for cleaning, inspection, and retrieval of loose objects. In addition, the primary and secondary sides of the AP1000 SGs are cleaned according to the guidance provided in RG 1.37. However, the AP1000 design takes an exception to quality standard ANSI N.45.2.1-1973 referenced in RG 1.37. The discussion of quality assurance documents is found in Section 17.3, "Quality Assurance During Design, Procurement, Fabrication, Inspection and/or Testing of Nuclear Plant Items," of this report.

5.4.2.1.3 Conclusions

The staff concludes that because the AP1000 SG materials satisfy staff criteria regarding materials selection, fabrication, and compatibility with the environments, the materials are acceptable and meet the requirements of GDC 1, 14, 15, and 31, as well as the requirements of 10 CFR Part 50, Appendix G.

5.4.2.2 Steam Generator Inservice Inspection

The staff reviewed DCD Tier 2, Section 5.4.2.5, "Steam Generator Inservice Inspection," in accordance with Section 5.4.2.2, "Steam Generator Tube Inservice Inspection," of the SRP to ensure periodic inspection and testing of critical areas and features to assess their structural and leaktight integrity. The SG ISI program is acceptable if it complies with the following:

- 10 CFR 50.55a, "Codes and Standards," as it relates to periodic inspection and testing of the RCPB as detailed in ASME Code, Section XI

- GDC 32, "Inspection of Reactor Coolant Pressure Boundary," as it relates to the accessibility of SG tubes for periodic testing

The guidelines for periodic inspection and testing of the SG tube portion of the RCPB are specified in the applicable standard technical specifications (STS). The applicable STS for Westinghouse plants are found in NUREG-1431, Volume 1, Revision 2, "Standard Technical Specifications Westinghouse Plants." TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program," notes that the current licensing basis for the SG tube surveillance requirements (i.e., technical specification—SG surveillance) will be included in this TS. This statement cannot be applied directly to the AP1000. However, the most recent NRC position on SG tube surveillance requirements for operating Westinghouse plants is found in NUREG-0452, Revision 4, "Standard Technical Specifications (STS) Pressurized Water Reactors." Thus, the staff reviewed the AP1000 SG ISI for consistency with the TS criteria in NUREG-0452, Revision 4.

5.4.2.2.1 Summary of Technical Information

The AP1000 design allows for inspection of pressure boundary parts, including individual tubes. In addition, the preservice and inservice inspections of the AP1000 SGs are performed according to the ASME Code and comply with the requirements of 10 CFR 50.55a.

The design of the AP1000 SGs includes the following openings to provide access to both the primary and secondary sides of the SG:

- four 45.7-cm (18-in.) diameter manways, one providing access to each chamber of the reactor coolant channel head and two in the steam drum

- two 10.2-cm (4-in.) diameter inspection openings at each end of the tubelane and above the top tube support plate

- additional access to the tube bundle U-bend through the internal deck plate at the bottom of the primary separators

- deck plate openings welded with hatch plates that are removable through grinding or gouging

5.4.2.2.2 Staff Evaluation

The staff reviewed DCD Tier 2, Section 5.4.2.5, "Steam Generator Inservice Inspection," in accordance with Section 5.4.2.2, "Steam Generator Tube Inservice Inspection," of the SRP to ensure that the SG tube bundle, as part of the RCPB, is designed to permit periodic inspection and testing of the tubes and critical areas, and includes features to assess the structural and leaktight integrity of the tubes, as required by 10 CFR Part 50, Appendix A, GDC 32.

As part of its evaluation, the staff reviewed the requirements for the SG Tube Surveillance Program contained in TS 5.5.4. The most recent generic technical specifications for SG ISI are found in NUREG-0452, Revision 4, "Standard Technical Specifications (STS) for the applicant Pressurized Water Reactors." The TS surveillance requirements for all domestic SGs are very similar, if not identical, to those in NUREG-0452, Revision 4. These requirements include methods for selecting and sampling tubes, inspection intervals, sample expansion criteria, actions to be taken in the event defects are identified, and reporting requirements.

The staff requested, in RAI 250.003, the applicant to revise the SG Tube Surveillance Program TS to be consistent with the surveillance requirements contained in NUREG-0452, Revision 4. In its response, the applicant provided a revision to AP1000 TS 5.5.5. The staff reviewed this response and did not find it entirely acceptable. The staff noted the following issues that need to be addressed further:

- The proposed AP1000 TS indicate that the provisions of TS SR 3.0.2 are applicable. However, the staff position, as articulated in Generic Letter (GL) 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," is that the surveillance interval extension in TS SR 3.0.2 does not apply to SG inspection intervals. This is based on the conditions defined in TS 5.5.4.3.a. and b. under which the surveillance interval for SG tube inspections may be extended to a maximum of once per 40 months. In addition, TS 5.5.4.3.b. addresses when the SG tube inspection frequency shall be increased to at least once per 20 months. Therefore, the staff finds the response was unacceptable until the TS 5.5.4 is revised to indicate that the provisions of TS SR 3.0.2 are not applicable. TS 5.5.4 includes Revision 4 of the SG Tube Surveillance Program. TS 5.5.4.3.d indicates that the provisions of TS SR 3.0.2 do not apply to extending the frequency of performing ISIs, as specified in TS 5.5.4.3.a and 5.5.4.3.b. The staff finds this to be acceptable because it excludes the application of TS SR 3.0.2 to extend SG surveillance frequencies.

- The proposed TS is included in AP1000 TS Table 5.5.4-1 which defines SG sample selection and inspection. However, NUREG-0452, Revision 4, includes a strategy for determining the minimum number of SGs to be inspected during first, second, and subsequent ISIs, depending on the preservice inspection performed. The applicant did not apply this strategy or any acceptable alternative. Therefore, the response is not acceptable until the applicant revises TS Table 5.5.4-1 to reflect the preservice inspection. The applicant revised the SG Tube Surveillance Program to include a note to TS Table 5.5.4-1 that indicates that all SGs shall be inspected during the first ISI if no preservice inspection was conducted. The staff finds this acceptable because the note to TS Table 5.5.4-1 provides an appropriate strategy for determining the minimum number of SGs to be inspected during the first, second, and subsequent ISIs, depending on the preservice inspection performed.

DCD Section 5.4.15, "Combined License Information," indicates that the COL applicant will address steam generator tube integrity with a Steam Generator Tube Surveillance Program and will address the need to develop a program for periodic monitoring of degradation of steam generator internals. This commitment is acceptable because such a program is needed to implement the TSs and because it addresses concerns addressed in Generic Letter 97-06, "Degradation of Steam Generator Internals." This is COL Action Item 5.4.2.2.3-1.

5.4.2.2.3 Conclusions

The staff concludes that the AP1000 SG ISI program is acceptable and meets the requirements of GDC 32. This conclusion is based on the accessibility of the AP1000 design for periodic inspection and testing of critical areas for structural and leakage integrity, and on the consistency of the SG Tube Surveillance Program TS with the TS requirements for Westinghouse domestic PWRs.

5.4.2.3 <u>Containment Bypass Resulting from Steam Generator Tube Rupture</u>

In SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Design," the staff identified a containment performance issue in which rupture of one or more SG tubes could lead to actuation of the SG safety relief valves, thereby creating the potential for a stuck-open safety relief valve, and an unisolable LOCA, with discharge of primary system radioactive inventory outside the containment. SECY-93-087 specifies that applicants for design certification for passive or evolutionary PWRs assess design features to mitigate containment bypass leakage during steam generator tube rupture (SGTR) events. The staff also recommends the following design features for consideration that could mitigate the release associated with an SGTR:

- a highly reliable (closed loop) SG shell-side heat removal system that relies on natural circulation and stored water sources
- a system that returns some of the discharge from the SG relief valve back to the primary containment
- increased pressure capacity on the SG shell side, with a corresponding increase in the safety valve setpoints

DCD Tier 2, Appendix 1B provides a risk-reduction evaluation of severe accident mitigation design alternatives (SAMDA) for the AP1000 design. A total of 15 design alternatives were selected for evaluation, including the 3 design features mentioned above. Each design alternative was evaluated to determine whether its safety benefit from risk reduction outweighs the costs of incorporating it in the plant. The applicant concluded that because of the small initial risk associated with the AP1000, none of these SAMDAs are cost beneficial.

In response to RAI 440.043, the applicant discussed the AP1000 design features that mitigate or prevent SG safety valve challenges during a rupture of multiple SG tubes, thus reducing the chance of containment bypass following an SGTR. This issue is discussed below.

5.4.2.3.1 AP1000 Steam Generator Tube Rupture Mitigation Design Features

The AP1000 design incorporates several automatic protection actions and the passive core cooling system (PXS) for mitigating the consequences of SGTR events. The automatic protection actions include reactor trip, actuation of the PXS, the RCP trip, termination of pressurizer heater operation, and isolation of the CVS flow and the SUFS. These protective actions result in automatic cooldown and depressurization of the RCS, termination of the break flow, stabilization of the RCS, prevention of SG overfill, and termination of steam release to the atmosphere to minimize offsite radiation. The AP1000 PXS responds to the SGTR events by automatically terminating the loss of reactor coolant without actuating the ADS or overfilling the SG.

In the SGTR scenario, continued loss of RCS inventory to the SG secondary side through the ruptured tubes leads to a reactor trip upon a low-pressurizer pressure or over-temperature delta-T signal. This will also cause a turbine trip. The CMTs automatically actuate upon a safeguards signal or low-pressurizer level. The PRHR HX automatically actuates upon the CMT actuation signal, high-pressurizer pressure, or low SG level. The PRHR HX acts to reduce the RCS pressure below the pressure of the secondary system and isolate the break flow to the faulted SG. The heat is removed from the RCS through the PRHR, instead of the intact SG power-operated relief valve (PORV), to stop the leak to the faulted SG. The CMTs provide heat removal and coolant inventory makeup for shrinkage in the RCS. During an SGTR transient, the CMTs inject water in the recirculation mode, exchanging cold borated water for hot RCS water. Because the CMTs do not drain during recirculation injection, the CMT level remains above the ADS actuation setpoint and, therefore, the ADS is not actuated.

The AP1000 also provides additional defense-in-depth to mitigate multiple SGTRs. The active, non-safety-related systems can be used to mitigate multiple SGTRs. The intact SG PORV is used to control the RCS pressure and isolate the break. The CVS auxiliary spray is used to reduce the RCS pressure to allow the pumped RNS to provide borated makeup flow to the system until the break is isolated. If both the active non-safety-related mitigation and the safety-related PRHR HX mitigation fails, the AP1000 provides another defense-in-depth method of mitigation. This method uses the ADS and passive safety injection.

On the secondary side, a PORV is installed on the outlet piping from each SG to provide a means for plant cooldown by discharging steam to the atmosphere when the turbine bypass system is not available. The PORV automatically opens to release steam when the steam pressure exceeds its predetermined set pressure, which is below the main steam safety valve (MSSV) set pressure. The PORV will close and reseat at a pressure below the opening setpoint as the steam pressure decreases. A block valve, upstream of the PORV, with a safety-related operator, closes automatically on low steam pressure to terminate steam release in the event of a PORV which is stuck open.

In the event that the PORV fails to open during a SGTR, the MSSVs could open. Because of the automatic SG overfill protection, which trips the CVS and SUFS flow, the SG is not overfilled and only steam is released through the MSSV. If the MSSV is assumed to fail open, the PRHR HX will not be able to terminate the loss of reactor coolant. The loss of primary system coolant through the SG tube and the stuck open valve eventually causes the CMTs to drain to the ADS actuation setpoint. Actuation of the ADS depressurizes the RCS in a controlled, staged manner, and eventually allows for gravity injection from the IRWST and the containment recirculation as the IRWST empties. The passive injection systems, CMTs, accumulators, and IRWST gravity injection provide inventory makeup and boration throughout the depressurization. The core remains covered and cooled throughout the sequence, and the plant achieves a safe, stable configuration without a release of fission products from the fuel matrix. Preventing the release of fission products from the core mitigates the beyond-design-basis containment bypass.

5.4.2.3.2 Multiple Steam Generator Tube Rupture Analysis

In DCD Tier 2, Section 15.6.3, "Steam Generator Tube Rupture," the applicant provided the design-basis analysis for a single-tube SGTR. The design-basis analysis assumed no operator actions, and assumed a PORV fails to reseat after it opens with continued release through the PORV until the block valve closed at low steamline pressure. The results showed no fuel failure, no SG overfilling, and the resulting offsite radiological doses within the dose acceptance limits.

In response to RAI 440.043, the applicant provided an analysis of the beyond-design-basis events of a multiple-tube rupture of five tubes. The intent of the analysis was to demonstrate the capability of the safety systems and automatic actions for mitigation of the MSGTR events. No operator actions were modeled in the analysis. The analysis was performed with the

MAAP4 code. MAAP4 is a fast-running, thermal-hydraulic computer code designed for severe accident analysis and was chosen by the applicant for the AP1000 probabilistic risk assessment (PRA) evaluation, as well as the evaluation of MSGTR. Section 19.1.10.5 of this report discusses the staff's evaluation of the use of MAAP4 for the AP1000 PRA evaluation.

The applicant analyzed two cases of five-tube rupture using the MAAP4 accident analysis code. The first assumed multiple SGTR with passive system response, and the second assumed multiple SGTR with failed open MSSV. In both cases, the accident was initiated by the simultaneous, double-ended failure of five cold side tubes at the top of the tube sheet. Startup feedwater system and the CVS were conservatively assumed to function because they tend to make the accident worse.

Case 1 is a passive system mitigation case with PRHR HX operation. The SUFS controls operate normally and throttle the SUFS based on the normal SG operating level. The CVS provides RCS makeup until it is isolated on a High-2 SG narrow range level. The results show that the faulted SG does not overfill and the safety valves do not open. Therefore, bypass does not occur. Throughout the events, the CMTs inject water in the recirculation mode, exchanging cold borated water for the hot reactor coolant. The CMTs do not drain and, therefore, the ADS does not actuate.

Case 2 is a passive system mitigation case with minimum PRHR heat removal. The SUFS controls are assumed to malfunction allowing SUFS flow to continue when the SG level increases above the normal level, until it is isolated on a High-2 SG narrow range level. The CVS provides RCS makeup until it is isolated on a High-2 SG narrow range level. The secondary system PORV is also conservatively assumed to not open. The combination of the low PRHR heat removal and the high SG level control causes the faulted SG pressure to exceed the MSSV lowest setpoint. When the MSSV opens, it is assumed to stick open, although the SG is not predicted to overfill. Therefore, the SGTR scenario turns into a small-break LOCA. Continued loss of coolant through the ruptured tubes and the stuck open MSSV eventually leads to the voiding of the RCS, the draining of the CMT, and the actuation of the ADS. The RCS is rapidly depressurized, which results in the actuation of the IRWST and eventual containment recirculation. The analysis results showed that the core remains covered and cooled with the collapsed liquid level well above the top of the active fuel throughout the entire transient. The maximum total release would be limited to the initial activity in the RCS, thus no significant fission product release occurs.

The staff notes that the MAAP4 code was used in the AP600 PRA success criteria analysis. WCAP-14896 provided benchmark studies with the NOTRUMP code for a series of small and medium LOCA event sequences to support its use for AP600 PRA success criteria. The staff found that, in most cases MAAP4 and NOTRUMP predicted similar trends for system behavior in the base cases and sensitivity analyses. On the basis of the benchmark study comparisons, the staff determined MAAP4 to be an adequate screening tool for addressing thermal-hydraulic uncertainties and determining PRA success criteria for the AP600, subject to certain limitations as discussed in WCAP-14869. The use of MAAP4 for AP1000 is the same as was used for AP600. The applicant evaluated the limitations discussed in WCAP-14869 and concluded that MAAP4 could be used as a screening tool for evaluating PRA success criteria for AP1000. The staff agrees with this conclusion with the limitation that those success paths that give marginal results with MAAP4 should be verified using a computer code which the NRC staff has reviewed. Since the results of the MSGTR events show the core is covered with the collapsed liquid level well above the top of the fuel and therefore have large margins to core uncovery, the staff concludes that no additional analyses are required and that no core damage will occur.

5.4.2.3.3 Conclusions

The AP1000 design has unique features for mitigating an SGTR as compared to the design of conventional PWRs. The analysis shows that the PORV will automatically open to release steam and will reseat within a very short time. Throughout the accident, the core remains covered without voiding, and the SG is not overfilled. If the PORV fails to open, the MSSV will open and close within a short time. Because of the automatic overfill protection, the SG is not overfilled, and the MSSV will release steam only. In the extremely unlikely event that the PORV fails to open coincident with a failure of the MSSV to reseat, an unisolable small-break LOCA scenario occurs with release to the atmosphere. In this event, continued steam release and loss of reactor coolant through the ruptured tubes will result in draining of the CMTs. The ADS will be actuated as the CMT level falls below the ADS actuation setpoint. Rapid depressurization of the RCS eventually results in the gravity injection from the IRWST, as well as the containment recirculation as the IRWST empties. Eventually, the break flow through the ruptured tubes stops. The analysis indicates that, throughout the entire accident, the core remains covered and cooled without core damage.

The staff concludes that there is reasonable assurance that the unique design features of the AP1000 are capable of mitigating the consequences of a multiple tube rupture, as specified by SECY-93-087. In the extremely unlikely event that the PORV fails to open coincident with a stuck-open MSSV, no core damage will occur, and the total release to the atmosphere would be limited to the initial activity of the RCS. The staff concludes that there is reasonable assurance that the containment bypass resulting from a multiple tube rupture poses no undue threat to public health and safety, and the AP1000 design satisfies the provisions of SECY-93-087.

5.4.3 RCS Piping

The RCS piping includes those sections of the RCS hot leg and cold leg piping interconnecting the RV, SGs, and RCPs. It also includes piping connected to the reactor coolant loop piping and primary components. The RCS piping accommodates the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. The piping in the AP1000 RCS is AP1000 Equipment Class A, and is fabricated according to ASME Code, Section III, Class 1 requirements, consistent with the requirements of 10 CFR 50.55a(c)(1). Lines with a 0.97 cm (3/8-inch) or less flow-restricting orifice qualify as AP1000 Equipment Class B, and are designed and fabricated to ASME Code, Section III, Class 2 requirements. Because the AP1000 CVS provides sufficient makeup of the reactor coolant in the event of a failure of a small line of 0.97 cm (3/8 in.) or less, Class B classification of small piping is exempted from ASME Code, Section III, Class 1, requirements in accordance with the exception permitted by 10 CFR 50.55a(c)(2)(i).

In DCD Tier 2, Section 5.4.3.2.1, "Piping Elements," the applicant provided a list of the piping connected to the RCS. The detailed RCS P&ID is shown in DCD Tier 2, Figure 5.1-5. It includes the pressurizer surge, spray, and auxiliary spray lines; pressurizer safety valves; the ADS with the first three stages connected to the pressurizer and the fourth stage connected to the hot legs; the reactor system head vent line; the accumulator lines; the CMT cold leg balance lines and injection lines; the PRHR system; the IRWST injection lines; the RNS pump suction line and discharge line; the CVS purification return lines to the SG channel head and the pressurizer spray; the CVS purification intake line from one RCS cold leg; and the drain, sample, and instrumentation lines. The RCS pressure boundary of these connecting lines start from their respective connections to the RCS and end at the second, normally-closed isolation valves or check valves in the respective lines, or the code safety valves, as defined in 10 CFR 50.2, "Definitions." All the RCS-connecting piping that constitutes the RCPB is designed to meet the ASME Code Section III requirements (with the one exception discussed below).

One exception to meeting the ASME Code Section III requirements is in the CVS. As discussed in DCD Tier 2, Section 3.9.6, the safety-related classification of the CVS ends at the third isolation valve in the purification loop intake line. The remainder of the purification subsystem of the CVS downstream of the third isolation valve inside containment consists of non-safety, Quality Group D components. Because the CVS purification intake line contains three isolation valves (CVS-PL-V001, -V002, -V003) that are maintained open during normal operation, the RCPB extends to the containment isolation valves of the CVS. However, because the portion of the CVS downstream of the three isolation valves can be isolated from the RCS, this portion need not be designed to ASME Class 1 requirements, in accordance with the exception criterion of 10 CFR 50.55a(c)(2)(ii). Regulatory Position C of RG 1.26 specifies that the portion of the RCPB that meets the exception criteria of 10 CFR 50.55a(c)(2) must consist of safety-related quality Group B or C components. However, DCD Tier 2, Section 5.2.1.3, describes many design enhancements that have been added to the Class D portion of the CVS, such as the use of three isolation valves of Class 1 design in the purification loop intake line, and seismic design of piping in the Class D portion. These design enhancements result in an alternate design that provides an acceptable level of quality and safety. As discussed in Section 5.2.1 of this report, the staff finds this alternative design to be acceptable.

To minimize the potential for thermal stratification that could increase cyclic stresses and fatigue usage, the pressurizer surge line is specifically designed with various degrees of continuous slope up from the hot leg connection to the pressurizer, as shown in DCD Tier 2, Figure 5.4-4. The surge line is also instrumented with strap-on resistance temperature detectors at three locations, one on the vertical section of pipe directly under the pressurizer and the other two on the top and bottom of the pipe at the same diameter on a more horizontal section of pipe near the pressurizer. These detectors monitor the temperature for indications of thermal stratification.

In DCD Tier 2, Table 5.4-7, the applicant listed the principal design data of the RCS piping, such as pipe sizes, thickness, and design pressure and temperature of the major RCS loop piping, pressurizer surge line, and other reactor coolant branch lines. All of the RCS piping and branch lines have a design pressure of 17.24 MPa (2485 psig). DCD Tier 2, Section 3.9.3, discusses the loading combinations, stress limits, and analytical methods for the structural evaluation of the RCS piping and supports for design conditions, normal conditions, anticipated transients, and postulated accident conditions. The RCS piping construction is subject to a quality assurance program with the required testing specified in DCD Tier 2, Table 5.4-8. This quality assurance program must also meet the requirements established by the ASME Code. The staff finds that the RCS-connecting piping that constitutes the RCPB is designed to meet the ASME Code Section III requirements and, therefore, is acceptable.

DCD Tier 2, Section 15.6, analyzes the consequences of the RCS piping breaks, including postulated cold leg double-ended guillotine breaks, to demonstrate their compliance with the respective acceptance criteria. For those low-pressure systems and components outside the containment with connections directly or indirectly to the RCS, SECY-93-087 specifies that those low-pressure portions be designed with the ultimate rupture strength at least equal to the full RCS operating pressure. This is addressed in generic safety issue GSI 105, "Interfacing System LOCA for LWR," as discussed in Chapter 20 of this report.

5.4.4 Main Steamline Flow Restriction

Each SG contains a flow restrictor in its steam outlet nozzle. The flow restrictor consists of seven venturi inserts welded to the SG outlet nozzle forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle, and the other six equally spaced around it. The steamline flow restrictor limits the steam flow rate from the secondary system to the choked flow of the venturi, in the unlikely event of a break in the main steamline. This flow restriction is needed to perform the following functions:

- limit rapid rise in containment pressure
- limit the reactor cooldown rate within acceptable limits
- reduce thrust forces on the main steamline piping
- limit pressure differentials on internal SG components, particularly the SG tube support plates

The steamline flow restrictor is configured to minimize the unrecovered pressure loss across the restrictor during normal operation. DCD Tier 2, Table 10.3.2-1, specifies the design data of the flow restrictors. The throat area of each venturi is 0.0186 m^2 (0.2 ft^2). With seven venturis in a flow restrictor, the equivalent throat area of the SG outlet is 0.13 m^2 (1.4 ft^2). The resultant pressure drop through the restrictor at 100-percent steam design flow rate of 3.40E+06 kg/hr (7.49E+06 lb/hr) is approximately 55.2 kPa (8 psi).

The staff reviewed the safety analysis of the design-basis event of steam system piping failure described in DCD Tier 2, Section 15.1.5. The analysis uses an effective nozzle flow area of 0.13 m^2 (1.4 ft^2) of the main steamline flow restrictors for each SG. The analysis results show that the acceptance criteria specified in SRP Section 15.1.5 are met. Therefore, the SG flow restrictor has an equivalent throat area of 0.13 m^2 (1.4 ft^2). Also, Item 8(b)(ii) in ITAAC DCD Tier 1, Table 2.2.4-4, requires a verification that the installed flow-limiting orifice within the SG main steamline discharge nozzle does not exceed 0.13 m^2 (1.4 ft^2). This is consistent with the safety analysis value and, therefore, the staff finds it to be acceptable.

5.4.5 Pressurizer

The pressurizer is a vertical, cylindrical vessel having hemispherical top and bottom heads, and containing saturated water and vapor. The pressurizer is connected from its bottom to one of the RCS hot legs through a surge line, which allows continuous coolant volume and pressure adjustments between the RCS and the pressurizer. The pressurizer, with the liquid and vapor maintained in equilibrium under saturated conditions, controls the RCS pressure during steady-state operations and transients. Major components of the pressurizer include the pressurizer spray system, electrical heaters, code safety valves, ADS valves, and the surge line. The pressurizer is the principal component of the RCS pressure control equipment. It also accommodates changes in RCS liquid volume, and limits the changes in RCS pressure as a result of reactor coolant temperature changes during all modes of plant operation. The pressurizer also serves as a convenient source of reactor coolant makeup for minor RCS leakage, and is the initial source of water to keep the RCS full in the event of a small-break LOCA in the RCS piping.

During steady-state operation at 100 percent power, approximately 50 percent of the pressurizer volume is water and 50 percent is steam. Electric immersion heaters in the bottom of the vessel keep the pressurizer contents at saturation temperature. A small continuous spray flow is provided through a manual bypass valve around each power-operated spray valve to minimize the boron concentration difference between the liquid in the pressurizer and the reactor coolant. During transient events, pressure increases, caused by insurge of reactor coolant, are mitigated by the pressurizer spray so that the high pressurizer pressure reactor trip setpoint is not reached. Conversely, during pressure decreases, caused by outsurge of reactor coolant, water-to-steam flashing and automatic heater operation keep the RCS pressure above the low pressurizer pressure reactor trip setpoint. The heaters are also energized on the high-water level during insurge to heat the subcooled surge water entering the pressurizer from the reactor coolant loop. The power to the pressurizer heaters are automatically blocked upon actuation of the CMTs (see DCD Tier 2, Section 7.3.1.2.3). This action prevents the heaters from attempting to repressurize the RCS during passive safety injection and, therefore, reduces the potential for SG overfill for an SGTR event. This pressurizer heater trip function is credited as a backup protection in the design-basis analyses of a loss of feedwater event and an SGTR event, as described in DCD Tier 2, Sections 15.2.7 and 15.6.3, respectively. In accordance with the TS screening criteria specified in 10 CFR 50.36, the pressurizer heater trip function is described in AP1000 TS Table 3.3.2-1, "Engineered Safeguards Actuation System Instrumentation," and is subject to AP1000 TS LCO 3.3.2, "Engineering Safety Feature Activation System (ESFAS) Instrumentation," and associated surveillance requirements.

The pressurizer safety valves provide overpressure protection of the RCS, as discussed in Section 5.2.2 of this report. In addition, the pressurizer provides for high-point venting of noncondensable gases from the RCS by remote manual operation of the first-stage ADS valves to vent the gas accumulated in the pressurizer following an accident. Section 5.4.12 of this report discusses this in more detail.

The AP1000 pressurizer has an internal volume of 59.5 m^3 (2100 ft^3), which is approximately 40 percent more volume than the pressurizers for current PWRs of a similar thermal power level. This increased pressurizer volume provides plant operating flexibility, minimizes challenges to the safety/relief valves, and eliminates the need for PORVs. DCD Tier 2, Section 5.4.5.1, provides the design bases for the sizing of the AP1000 pressurizer. These will ensure that the plant can meet the following conditions without the need for a PORV:

- The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.
- The water volume is sufficient to prevent (1) a reactor trip during a step-load increase of 10 percent of full power, with automatic reactor control, and (2) uncovering the heaters following reactor trip and turbine trip, with normal operation of control systems and no failures of the nuclear steam supply systems.
- The steam volume is large enough to (1) accommodate the surge resulting from a step-load reduction from 100-percent power to house loads without reactor trip, assuming normal operation of control systems, and (2) prevent water relief through the safety valves following a complete loss of load with the high-water level initiating a reactor trip, without steam dump.
- A low pressurizer pressure safeguard actuation ("S") signal will not be activated because of a reactor trip and turbine trip, assuming normal operation of control and makeup systems and no failures of the nuclear steam supply systems.

The staff reviewed the pressurizer performance during anticipated operational occurrences (AOO) and postulated accidents as part of its design-basis accident analysis review discussed in Chapter 15 of this report. The results of the analyses demonstrate that the acceptance criteria specified in SRP Chapter 15 for the transients and accidents are met (i.e., the DNBR limit is met for all AOOs, the RCS pressure is within 110 percent of the RCS design pressure for the pressurization events, and the acceptance criteria of 10 CFR 50.46 are met for LOCAs). Therefore, the staff finds the pressurizer design to be acceptable.

5.4.6 Automatic Depressurization System Valves

The ADS valves are part of the RCS and interface with the PXS. The ADS is divided into two groups and four depressurization stages, with a total of 20 valves. These stages connect to the RCS at different locations. The first, second, and third stage valves are included as part of the pressurizer safety and relief valve (PSARV) module, which is connected to nozzles on top of the pressurizer. The two groups are on different elevations separated by a steel plate. The first stage ADS valves in each group are two motor-operated 10.2-cm (4-in.) valves in series. The second and third stage ADS valves each have two motor-operated 20.3-cm (8-in.) valves in series. The fourth stage ADS valves are 35.56-cm (14-in.) squib valves arranged in series with normally open, dc-powered, motor-operated valves. The outlets of the first three stages in each group are combined into a common discharge line to the IRWST. This discharge line has a vacuum breaker to help prevent water hammer following ADS operation by limiting the pressure reduction caused by steam condensation in the discharge line, thus limiting the potential for liquid backflow from the IRWST. The fourth stage ADS valves connect to the RCS hot legs, and are interlocked so that they cannot be opened until RCS pressure has been substantially reduced.

DCD Tier 2, Section 6.3, discusses the operation of the PXS. DCD Tier 2, Section 7.3, describes the actuation logic and setpoints for opening various stages of the ADS valves. Opening of the ADS valves is necessary for the PXS to provide emergency core cooling following postulated accident conditions. The first stage valves may also be used to remove noncondensable gases from the steam space of the pressurizer, if necessary, following an accident.

Section 6.3, "Passive Core Cooling System," of this report evaluates the ADS functional performance (as part of the PXS performance). Chapter 15 of this report evaluates the safety analyses of various design-basis accidents. The analysis results of design-basis accidents, such as the small-break LOCAs described in DCD Tier 2, Section 15.6.5, demonstrate that the ADS design and the passive core cooling system meet the acceptance criteria specified in 10 CFR 50.46. Therefore, the staff finds the ADS design to be acceptable.

5.4.7 Normal Residual Heat Removal System

The AP1000 normal RNS is a non-safety-related system and is not required to operate to mitigate design-basis events. However, the RNS does perform the following safety-related functions:

- containment isolation of RNS lines penetrating containment using containment isolation valves according to the criteria specified in DCD Tier 2, Section 6.2.3
- preservation of the RCS pressure boundary integrity using pressure isolation valves according to the criteria specified in DCD Tier 2, Section 5.4.8
- provide a flow path for long-term, post-accident makeup to the containment inventory

5.4.7.1 <u>Residual Heat Removal System Design Bases</u>

The RNS performs the following non-safety-related functions. Their design bases are also described below.

- Shutdown Heat Removal

  The RNS is designed to remove both residual and sensible heat from the core and the RCS during shutdown operations, with the capability to (1) reduce the temperature of the RCS from 176.7 °C (350 °F) to 51.7 °C (125 °F) within 96 hours after shutdown during the second phase of plant cooldown (after the initial RCS cooldown is accomplished by the main steam system), and (2) maintain the reactor coolant temperature at or below 51.7 °C (125 °F) for the entire plant shutdown.

- Shutdown Purification

  The RNS is designed to provide RCS and refueling cavity purification flow to the CVS during refueling operations, with the purification flow rate consistent with that specified in DCD Tier 2, Table 9.3.6-1.

- In-Containment Refueling Water Storage Tank Cooling

  The RNS is designed to provide cooling for the IRWST during operation of the PRHR HX or during normal plant operations, when required. The RNS is designed to be manually initiated by the operator. During normal operation, the RNS, with both subsystems of RNS pumps and heat exchangers available, will limit the IRWST water temperature to no greater than 48.9 °C (120 °F). During extended operation of the PRHR HX, the RNS will limit the IRWST water temperature to less than the boiling temperature.

- Low-Pressure RCS Makeup and Cooling

  The RNS is designed to be manually initiated by the operator following the actuation of the ADS. The RNS provides low-pressure makeup from the cask loading pit to the RCS (once the pressure in the RCS falls below the shutoff head of the RNS pumps), thus providing additional margin for core cooling.

- Low-Temperature Overpressure Protection

  The RNS is designed to provide LTOP for the RCS during refueling, startup, and shutdown operations to limit the RCS pressure to the specifications found in 10 CFR Part 50, Appendix G.

- Spent Fuel Pool Cooling

  The RNS is designed to have the capability to supplement or take over the cooling of the spent fuel pool when it is not needed for normal shutdown cooling.

5.4.7.2 <u>Residual Heat Removal System Design and Components</u>

In DCD Tier 2, Section 5.4.7.2, the applicant described the AP1000 RNS design, including specific design features to address the concerns related to mid-loop operation and interfacing system LOCA, respectively. The RNS consists of two mechanical trains of equipment; each consists of one pump and one heat exchanger. The two trains share a common suction line from the RCS and a common discharge header. The RNS also comprises piping, valves, and instrumentation necessary for system operation, as shown in DCD Tier 2, Figure 5.4-7.

Inside containment, the RNS suction header is connected to an RCS hot leg with a single step-nozzle connection. The suction header comprises two parallel lines with two sets of two normally closed, motor-operated isolation valves in series for single-failure consideration. These isolation valves comprise the RCS pressure boundary. The two lines are connected to a common suction header. This suction alignment is for reactor cooling during normal shutdown operation. A single line from the cask loading pit is connected to the suction header to provide a flow path for low-pressure makeup of the RCS.

Once outside containment, the suction header contains a single, normally closed, motor-operated isolation valve. Downstream of the isolation valve, the header branches into two separate lines, one to each pump. A normally open manual isolation valve is located upstream of the RNS pumps for pump maintenance.

The discharge of each RNS pump is routed directly to its respective RNS heat exchanger. A mini-flow line, which contains an orifice and is sized for a sufficient pump flow rate when the pressure in the RCS is above the RNS pump shutoff head, is routed from downstream of the heat exchanger to upstream of the pump suction. The outlet of each heat exchanger is routed to the common discharge header, which contains a normally closed, motor-operated isolation valve before penetrating the containment.

Once inside containment, the common discharge header contains a check valve that acts as a containment isolation valve. Downstream of the check valve, the discharge header branches into two lines routed to the DVI lines. These branch lines each contain two check valves in series that comprise the RCS pressure boundary. A line is branched from the common header to the CVS demineralizers for shutdown purification of the RCS. Another line is routed from the discharge header to the IRWST for cooling of the tank.

The RNS contains a single safety/relief valve, located off the RNS suction header inside containment that discharges to the IRWST. This relief valve is utilized for LTOP of the RCS.

In DCD Tier 2, Table 3.2-3, the applicant provided the safety classification and seismic categories of the RNS components. The portions of the RNS piping and components from the RCS up to, and including, the outer RNS suction isolation valve or outer RNS discharge check valve constitute the RCPB, and are designed with safety Class A requirements. The RNS RCPB valves include V001A, V001B, V002A, V002B, V015A, V015B, V017A, and V017B. DCD Tier 2, Section 5.4.8, states that these valves are manufactured to the requirements of ASME Code Class I. The portions from the RCPB to the containment isolation valves outside the containment are designed to safety Class B requirements. The RNS containment isolation valves include V002A, V002B, V011, V012, V013, V021, V022, V023, and V061. These valves (except for RCPB valves V002A and V002B which are ASME Code Class 1) are manufactured to ASME Code Class 2 requirements. The inside containment portions extending to the containment isolation valves outside containment are designed for full RCS pressure. The system piping and components outside containment, including the pumps, valves, and heat exchangers, are safety Class C, and have a design pressure and temperature such that full RCS pressure is below the ultimate rupture strength of the piping.

The design classifications of the RNS components discussed above comply with GDC 1 which specifies that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. The whole RNS system, except for the heat exchanger shell vents, is designed for seismic Category I for pressure retention. This complies with GDC 2 which specifies that the SSCs important to safety shall be designed to withstand the effects of natural phenomena, such as earthquakes, without loss of capability to perform their safety functions. This also complies with RG 1.29 which specifies that the SSCs that constitute the RCPB are designated seismic Category I, and should be designed to withstand the effects of the SSE and remain functional. The staff finds that the RNS design will perform its safety-related functions of containment isolation and preservation of the RCPB integrity and, therefore, is acceptable.

5.4.7.3 Shutdown Operation Design Features

In SECY-93-087, the staff specified that passive plants must have a reliable means of maintaining decay heat removal capability during all phases of shutdown activities, including refueling and maintenance. The staff's review of the AP1000 design with respect to shutdown operations is based on the applicant's systematic assessment of shutdown operation concerns identified in NUREG-1449, "Shutdown and Low-Power Operations at Commercial Nuclear Power Plants in the United States," which encompasses mid-loop operation. DCD Tier 2, Appendix 19E, "Shutdown Evaluation," provides this assessment. Section 19.3 of this report discusses the staff's evaluation of the shutdown operation issues. This section describes the RNS design features that address the issues raised in NUREG-1449 and GL 88-17, "Loss of Decay Heat Removal," regarding mid-loop operation. Each design feature of the RNS and its design bases are described below:

- Loop Piping Offset

  The levels of the RCS hot legs and cold legs are offset vertically with the hot leg nozzles 0.445 m (17.5 in.) below the cold leg nozzles so that the RCS can be drained with the hot leg level remaining much higher than in traditional designs for venting of the SGs prior to nozzle dam insertion. Furthermore, this loop piping offset allows an RCP to be replaced without removing a full core.

- Step-Nozzle Connection

  The RNS employs a step-nozzle connection to the RCS hot leg to minimize the likelihood of air ingestion into the RNS pumps during RCS mid-loop operations. The step-nozzle connection substantially lowers the RCS hot leg level at which a vortex occurs in the RNS pump suction line as a result of the lower fluid velocity in the hot leg nozzle.

- Self-Venting Suction Line

  The RNS pump suction line slopes continuously upward from the pump to the RCS hot leg with no local high points (where air could collect and cause a loss of RNS capability). This self-venting suction line will refill after a pump trip. The pumps can be immediately restarted once an adequate level is reestablished in the hot leg.

- Hot-Leg Level Instrumentation

  The AP1000 RCS contains level instrumentation in each hot leg with a readout in the MCR. Alarms are also provided to alert the operator when the RCS level is approaching a low level. Additionally, the isolation valves in the RCS drain line are interlocked to close on a low RCS level during shutdown operations.

- Reactor Vessel Outlet Temperature

  Each hot leg is provided with a wide-range, thermowell-mounted resistance temperature detector for measurement of reactor coolant fluid temperature in the hot leg when in reduced inventory conditions.

- Automatic Depressurization System Valves

  The ADS valves of the first three stages are required to be open to provide a vent path to prevent RCS pressurization whenever the CMTs are blocked during shutdown conditions while the RV upper internals are in place.

- Other Features for Shutdown Operations

  The RNS contains instrumentation to monitor and control system performance. System parameters necessary for RNS system operation that are monitored in the MCR include the following instrumentation which also allows mid-loop operations to be performed from the MCR:

  - RNS pump flow discharge pressure
  - RNS heat exchanger inlet and outlet temperatures
  - RNS heat exchanger outlet flow and bypass flow
  - RCS wide-range pressure

The staff's evaluation of shutdown operations and AP1000 design features to support shutdown operations is based on DCD Tier 2, and is provided in Section 19.3 of this report. The staff concludes that the AP1000 design features, including those of the RNS, are adequate to support operations at shutdown and low power conditions, as discussed in Section 19.3 of this report, and therefore, are acceptable.

5.4.7.4 Interfacing-Systems LOCA Design Features

In SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," as well as in SECY-93-087, the staff specified that ALWR designs should reduce the possibility of a LOCA outside containment by designing, to the extent practical, all systems and subsystems connected to the RCS to an ultimate rupture strength at least equal to full RCS pressure. SECY-90-016 also specifies guidance for those systems that have not been designed to withstand full RCS pressure.

DCD Tier 2, Section 5.4.7.2.2, discusses the AP1000 design features that address the inter-system LOCA (ISLOCA). Section 3.1 of WCAP-15993, "Evaluation of the AP1000 Conformance to Inter-System Loss-of-Coolant Accident Acceptance Criteria," issued November 2002, provides a design evaluation of the RNS for conformance to the ISLOCA acceptance criteria. The AP1000 RNS design contains the following ISLOCA features:

- Increased Design Pressure

  The portions of the RNS from the RCS up to, and including, the containment isolation valves outside containment are designed to the full RCS operating pressure. The portions of the system downstream of the suction line containment isolation valve and upstream of the discharge line containment isolation valve, including the pumps, valves, flanges, fittings, and heat exchangers, have a design pressure of 6.21 MPa (900 psi), approximately 40 percent of the RCS operating pressure, so that its ultimate rupture strength is not less than the operating pressure of the RCS. However, the pump seal does not meet this criterion. This exception is discussed in the staff's evaluation of GSI 105, "Interfacing Systems LOCA at Light Water Reactors," in Chapter 20 of this report.

- Additional Reactor Coolant System Isolation Valve

  The RNS contains an additional isolation valve in the pump suction line from the RCS. This motor-operated containment isolation valve is designed to full RCS pressure, and provides an additional barrier between the RCS and lower pressure portions of the RNS.

- Residual Heat Removal System Relief Valve

  The RNS relief valve is connected to the RNS pump suction line inside containment to provide LTOP of the RCS. It is connected to the high-pressure portion of the pump suction line, thereby reducing the risk of overpressurizing the low-pressure portions of the system.

- Features Preventing Inadvertent Opening of Isolation Valves

  The motor-operated isolation valves connected to the RCS hot leg are interlocked to prevent their opening at RCS pressures above 3.21 MPa (450 psig). These valves are also interlocked to prevent their being opened unless the isolation valve from the IRWST to the RNS pump suction header is closed. In addition, the power to these valves is administratively blocked at the valve motor control center to prevent their inadvertent opening.

- Reactor Coolant System Pressure Indication and High Alarm

  The RNS contains an instrumentation channel that indicates pressure in each RNS pump suction line. A high pressure alarm is provided in the MCR to alert the operator to a condition of rising RCS pressure that could eventually exceed the design pressure of the RNS.

The staff's evaluation of the interfacing system LOCA is addressed in the discussion of GSI 105, in Chapter 20 of this report. The staff finds that the RNS design features meet the ISLOCA specifications in SECY-90-016 and SECY-93-087 and, therefore, are acceptable.

5.4.7.5 Residual Heat Removal System Operation and Performance

In DCD Tier 2, Section 5.4.7.4, the applicant provided a general description of the RNS operation for the pertinent phases of plant operation (plant startup, plant cooldown, refueling, accident recovery operations, and spent fuel pool cooling). System operations are controlled and monitored from the MCR, even during mid-loop operations.

For accident recovery operations, the RNS can provide low-pressure RCS makeup upon actuation of ADS. The staff reviewed the AP600 emergency response guidelines (ERG), which are applicable to the AP1000, to evaluate a possible system interaction caused by the RNS operation, which may adversely affect the performance of the passive safety systems. For post-LOCA recovery, the ERGs instruct the operators to actuate the RNS and align the RNS pumps to take suction from the IRWST and inject into the RCS to provide additional core cooling, if the CMT level begins to decrease. Operation in this mode provides additional injection flow to the RCS, thereby providing additional core cooling margin. Because the RNS pumps are aligned to inject into the RCS via the DVI lines, which are also the injection paths of the CMTs and IRWST, these shared connections can result in interactions with the PXS.

WCAP-15992, Revision 1, "AP1000 Adverse System Interactions Evaluation Report," provides an evaluation of the potential for adverse system interactions of the RNS and the PXS. For a small-break LOCA, the operation of the RNS pumps in the injection mode increases the backpressure on the CMT and prevents the CMT from draining to the ADS-4 actuation setpoint, thereby preventing the ADS-4 valves from actuating. Operation of the RNS pumps will refill the RCS and recover the water level in the pressurizer without the need to actuate ADS-4 valves. For a large-break LOCA, the capacity of the RNS will not be sufficient to prevent the CMT from draining and subsequent ADS-4 actuation. Therefore, RNS operation has no adverse impact.

However, because the RNS is aligned to the IRWST following draindown of the cask loading pit, continued long-term operation of the RNS pumps could result in the IRWST draining at a faster rate than if the RNS pumps were not operating. This is not a concern as long as the RNS pumps continue to operate, and provide a higher injection rate than the gravity injection from the IRWST or the containment recirculation path. If the RNS pumps were to fail, the impact to post-accident RCS makeup by gravity injection from the IRWST and containment recirculation would be insignificant because of the use of the cask loading pit as a source of RCS makeup. For the AP1000 design, the RNS is initially aligned to the cask loading pit. The RNS aligns to the IRWST after the draindown of the cask loading pit. This operation delays the draining of the IRWST and extends the time at which containment recirculation is initiated so that the core decay heat level is reduced at the time of containment recirculation initiation. In addition, the use of the cask loading pit provides additional post-accident water inventory, thus increasing the containment floodup level, which improves the driving head available for containment recirculation flow. Based on the discussion above, the staff finds this system interaction to be acceptable.

5.4.7.6 Design Evaluation

The staff reviewed the RNS design for compliance with the following requirements:

- GDC 1, as it relates to the quality standards of the SSCs important to safety
- GDC 2, as it relates to the seismic design of the SSCs important to safety to withstand an SSE and remain functional, with acceptability based on meeting RG 1.29
- GDC 4, as it relates to the dynamic effects associated with flow instability and loads
- GDC 5, as it relates to the prohibition on SSCs important to safety from being shared among nuclear power units
- GDC 19, as it relates to the provision of a control room from which actions can be taken to operate the nuclear power unit safely
- GDC 34, as it relates to the ability of the residual heat removal system to transfer fission product decay heat

The RNS is designed for a single nuclear power unit, and is not designed to be shared between units. The RCPB portion of the RNS is designed as safety Class A, and the containment isolation valves of the RNS are designed as safety Class B. The remaining portions are designed as safety Class C. The pressure boundary is classified as seismic Category I and is designed to withstand an SSE for pressure retention. The RNS is operated from the MCR. The high-energy piping of the RNS (i.e., the RNS suction and discharge portions that constitute the RCPB) are subject to LBB criteria for protection against dynamic effects. This is identified in DCD Tier 2, Table 3B-1 and Figure 3E-2. Therefore, the RNS meets GDC 1, 2, 4, 5, and 19. Because the RNS is not designed to provide safety-related decay heat removal function for mitigation of design-basis events, the safety-related PRHR HX complies with the heat removal function of GDC 34. Section 6.3 of this report discusses the evaluation of the PRHR HX.

5.4.7.7 Inspection and Testing Requirements

DCD Tier 2, Section 5.4.7.6, describes inspection and testing requirements for the RNS. Preoperational tests, which include valve inspection and testing, flow testing, and verification of heat removal capability, verify the proper operation of the RNS. The inspection and test requirements of the RNS valves are consistent with those identified in DCD Tier 2, Sections 5.2.4 and 6.6, respectively, for the valves that constitute the RCPB and the valves that isolate the line penetrating containment. In addition, these valves are included in DCD Tier 2, Table 3.9-16, and are subject to IST. The staff finds that the applicant has set proper inspection and test requirements for the RNS valves performing the safety-related functions of containment isolation and RCPB integrity preservation.

The staff verified that the set pressure and the relieving capacity of the relief valve, RNS-V021, which provides low-temperature overpressure protection, are consistent with the values specified in DCD Tier 2, Table 5.4-17. The relief valve relieving capacity will be certified in accordance with ASME Code Section III, NC-7000. The staff finds this to be acceptable.

DCD Tier 2, Table 5.4-14, specifies the minimum flow rates needed to meet the functional requirements of cooling the RCS during shutdown operations and low-pressure makeup to prevent 4th stage ADS actuation for a small-break LOCA, respectively. These shutdown cooling and low-pressure makeup flow rates are confirmed through tests with the RNS pump suction aligned to its respective operations, (i.e., with the suction aligned to the RCS hot leg and the cask loading pit, respectively). DCD Tier 2, Table 5.4-14, specified the RNS HX heat removal capability, which is verified through the manufacturer's test results and data. The staff finds that these tests to confirm the RNS flow and heat transfer capabilities are acceptable.

5.4.7.8 <u>Regulatory Treatment of the Residual Heat Removal System</u>

The RNS is a non-safety-related system that is not required to operate to mitigate design-basis events. Therefore, the RNS is not required to meet safety-related system requirements. However, the RNS is a defense-in-depth system that provides the first line of defense during an accident to prevent unnecessary actuation of the passive core cooling systems. Regulatory oversight of the active non-safety systems in passive plant designs is subject to a staff evaluation of the regulatory treatment of non-safety systems (RTNSS). Chapter 22 of this report provides a detailed evaluation of the RTNSS issue.

The staff describes the RTNSS process in SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs." The goal of the RTNSS process is to (1) provide insights on the importance of non-safety-related systems to the overall safety of the passive advanced reactor design, and (2) assist in determining what, if any, additional regulatory controls should be applied to RTNSS-identified systems. The RTNSS process involves using both probabilistic and deterministic criteria to (1) determine whether regulatory oversight for certain non-safety-related systems is needed, (2) identify the risk-significant SSCs for regulatory oversight, and (3) decide on an appropriate level of regulatory oversight for the various identified SSCs commensurate with their risk importance.

Because the important non-safety-related SSCs identified through the RTNSS process do not meet the screening criteria specified in 10 CFR 50.36 for inclusion in the TS limiting conditions for operation, the applicant proposed a mechanism to provide for short-term availability control of these systems. DCD Tier 2, Section 16.3, provides short-term availability administrative controls for the important non-safety-related SSCs identified in the RTNSS. For each RTNSS-identified SSC, the operability requirements for the required functions and system configurations are specified for various modes of operation, and the required actions and completion times are specified for conditions not meeting the operability requirements. Surveillance frequency requirements are also specified to confirm operability of the SSCs. DCD Tier 2, Section 16.3.2, includes a commitment that the COL applicant referencing the AP1000 design will develop and implement procedures consistent with the availability controls. The AP1000 DCD will also include these administrative availability controls.

In WCAP-15985, "AP1000 Implementation of the Regulatory Treatment of Non-Safety-Related Systems Process," the applicant provided the results of its evaluation based on the RTNSS screening process. The RNS was identified as an important system, necessary for shutdown decay heat removal to support mid-loop operation with reduced reactor coolant inventory. Therefore, the RNS is subject to additional regulatory controls. In addition, the RNS provides a non-safety-related means of injecting the IRWST water into the RCS following ADS actuation to provide margin in the PRA sensitivity studies to mitigate at-power and shutdown events. DCD Tier 2, Table 16.3-2, Sections 2.1 and 2.2, specify the administrative short-term availability controls of the RNS functions at various modes of operation. In addition, DCD Tier 2, Table 16.3-2, specifies the availability controls of the RNS supporting systems, such as the CCS, the service water system, and the alternating current power supplies. The staff has reviewed DCD Tier 2, Table 16.3-2, and concludes that proper administrative controls are provided to ensure the short-term availability of the RCS to perform its required functions.

5.4.8 Valves

The design bases, design evaluation, qualification testing, and ISI and IST of valves associated with the RCS and RCS-connected systems is collectively discussed in Sections 3.9.3, 3.9.6, 3.10, 5.2.3, 5.2.4, and 6.6 of this report.

5.4.9 Reactor Coolant System Pressure Relief Devices

The AP1000 design, which does not have a PORV in the reactor coolant system, relies on the PSVs connected to the pressurizer to provide overpressure protection of the RCS during power operation, in accordance with GDC 15 in Appendix A to 10 CFR Part 50. GDC 15 requires the RCS and its associated auxiliary, control, and protection systems to be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences. The AP1000 also relies on the relief valve on the suction line of the RNS to provide LTOP consistent with the guidelines of Section 5.2.2 of the SRP, including BTP RSB 5-2.

It should be noted that the ADS valves, which provide a means to depressurize the RCS as part of the PXS, are not pressure relief devices for overpressure protection. The first three stages of the ADS are connected to the pressurizer; the first stage can also be used to vent noncondensable gases following an accident.

5.4.9.1 Pressurizer Safety Valves

The AP1000 has two PSVs, which are of the totally enclosed, pop-type, spring-loaded, and self-actuated by direct fluid pressure. No loop seal in the piping exists between the pressurizer and the PSVs to collect the steam condensate. The steam condensate will drain back to the pressurizer, and will not be discharged as a water slug during the initial opening of the valve. Each PSV discharge is directed through a rupture disk, located at the end of the discharge piping, to the containment atmosphere. The rupture disk is provided to contain leakage past the valve, and is designed with a substantially lower set pressure than that of the PSV. This will ensure PSV discharge. A small pipe is connected to the discharge piping and directed to the

RCDT to drain away condensed steam leaking past the safety valve. Positive position indication is provided for the PSVs, in accordance with the requirements of 10 CFR 50.34(f)(2)(xi), which requires direct indication of relief and safety valve position (open or closed) be provided in the MCR. Temperatures in the discharge lines are measured, and an indication and high-temperature alarm are provided in the control room for indication of any leakage or relief through the associated valve. The PSVs are designed to prevent RCS pressure from exceeding 110 percent of system design pressure. DCD Tier 2, Table 5.4-17, specifies the design parameters of the PSVs. As addressed in Section 5.2.2 of this report, the sizing of the PSVs with 3-percent accumulation meets the requirements of GDC 15. Therefore, the staff finds this to be acceptable.

In 10 CFR 50.34(f)(2)(x), the NRC requires a test program and associated model development, as well as the conduct of tests, to qualify RCS relief and safety valves for all fluid conditions expected under operating conditions, transients, and accidents. This has been done through the tests of similar safety valves within the EPRI safety and relief valve test program, which found that the safety valves were adequate for steam flow and water flow, even though water flow is not anticipated through the PSVs. Item II.D.1, "Testing Requirements," in Chapter 20 of this report addresses the resolution of the PSV testing program. The PSVs are also subjected to preservice and inservice hydrostatic tests, seat leakage tests, operational tests, and inspections. This is done through the IST specified in DCD Tier 2, Table 3.9-16, as well as the ISI for ASME Code Class 2 and 3 components, as specified in DCD Tier 2, Section 6.6. The test program for the safety valves complies with the requirements of ANSI/ASME Code of Operations and Maintenance, Part 1, "Requirements for Inservice Testing of Nuclear Power Plant Pressure Relief Devices." Therefore, the staff finds the applicant's test program to be acceptable.

5.4.9.2 Residual Heat Removal System Relief Valve

The RNS relief valve on the RNS pump suction line is spring-loaded and self-actuated by direct fluid pressure, and is designed for water relief with an accumulation of 10 percent of the set pressure. The set pressure (setpoint) is the lower of the values determined on the basis of the RNS design pressure or the RV low-temperature pressure limit. DCD Tier 2, Table 5.4-17, specifies the design parameters of the RNS relief valve, including the set pressure and relieving capacity. Section 5.2.2 of this report discusses the determination of the set pressure and relieving capacity. The lowest permissible lift set pressure is determined by the required NPSH for the RCPs. Position indication for the RNS relief valve is provided in accordance with 10 CFR 50.34(f)(2)(xi), which requires that direct indication of relief and safety valve position (open or closed) be provided in the MCR. Therefore, the staff finds this to be acceptable.

RCS pressure relief devices must be subjected to qualification tests for all fluid conditions expected under operating conditions, transients, and accidents, as required by 10 CFR 50.34(f)(2)(x). DCD Tier 2, Section 5.4.9.4, states that the RNS relief valve is designed for water relief and is not an RCS pressure relief device because it has a set pressure less than the RCS design pressure. Therefore, the valve selected for the RNS relief valve is independent from the EPRI safety and relief valve test program. Because the RNS relief valve is not an RCPB valve, and is designed for LTOP, the staff agrees it need not be included in the EPRI test program for the safety and relief valve test program. As specified in DCD Tier 2, Table 3.2-3, the RNS relief valve is an AP1000 Class 2 component, and will be designed, manufactured, and tested to ASME Section III, Class 2 requirements. In addition, the RNS relief valve is also subject to IST, as specified in DCD Tier 2, Table 3.9-16, for its safety-related missions and functions. The staff finds that these test requirements for the RNS relief valve comply with the ASME Code, Section III, requirements and, therefore, are acceptable.

5.4.10 RCS Component Supports

Sections 3.9.3.3 and 3.12.6 of this report describe the design bases and design evaluation of the RCS component supports. Sections 5.4.2.2 and 6.6 of this report discuss ISI of RCS components.

5.4.11 Pressurizer Relief Discharge

The AP1000 design does not have a pressurizer relief discharge system. The AP1000 employs neither power-operated pressurizer relief valves nor a pressurizer relief discharge tank. Some of the functions provided by the pressurizer relief discharge system in previous nuclear power plants are provided by portions of other systems in the AP1000.

The staff reviewed the AP1000 pressurizer relief discharge using SRP Section 5.4.11, "Pressurizer Relief Tank," for guidance. The SRP acceptance criteria specify that the design meet GDC 2, as it relates to the protection of safety-related systems from the effects of earthquakes, and GDC 4, as it relates to a failure of the system resulting in missiles or adverse environmental conditions that could result in damage to the safety-related systems or components. Conformance with GDC 2 is demonstrated by meeting the guidelines of RG 1.29, "Seismic Design Classification," Positions C.2 and C.3. Position C.2 addresses those portions of the SSCs which should be designed and constructed such that an SSE could not cause their failure and result in reduced functioning of any seismic Category I equipment, or cause an incapacitating injury to occupants in the MCR. Position C.3 addresses the extension of seismic Category I design requirements to the first seismic restraint beyond the defined boundaries. Conformance with GDC 4 is demonstrated by meeting the acceptance criteria of SRP Section 5.4.11, as applicable.

DCD Tier 2, Section 5.2.2, "Overpressure Protection"; Section 5.4.6, "Automatic Depressurization System Valves"; Section 5.4.9, "Reactor Coolant System Pressure Relief Devices"; Section 5.4.11, "Pressurizer Relief Discharge"; Section 5.4.12, "Reactor Coolant System High Point Vents"; and Section 6.3, "Passive Core Cooling System"; discuss the systems and components for AP1000 pressurizer relief discharge. This equipment is located inside containment and is designed to provide overpressure protection for the RCS during power operation. Two pressurizer safety valves are located on top of the RCS pressurizer. DCD Tier 2, Table 3.2-3 and Section 3.2, state that the pressurizer safety valves are classified as AP1000 equipment Class A (American Nuclear Society (ANS) safety Class 1), seismic Category I, and ASME Code Class 1. These valves are tested in accordance with requirements of ASME Code, Section XI.

The pressurizer safety valves are spring-loaded, self-actuated by direct fluid pressure, and have backpressure compensation features. They are the totally enclosed, pop-type, and are designed to reclose and prevent further flow of fluid after normal conditions have been restored. Because loop seals are not installed between the pressurizer and safety valves, steam condensation flows back into the pressurizer, instead of forming a water slug that would blow out during initial safety valve actuation. Although the valves are designed for the flow of both steam and water, water is not expected to flow through the valves. The normal RNS relief valve is designed for water relief.

The pressurizer safety valves are sized on the basis of the analysis of a complete loss of steam flow to the turbine with the reactor operating at 102 percent of rated power. In the analysis, no credit is taken for the operation of the pressurizer level control system, pressurizer spray system, rod control system, steam dump system, steamline PORVs, or direct reactor trip on turbine trip. The feedwater system is also assumed to be lost. Under these conditions, the total pressurizer safety valve capacity is at least as large as the maximum surge rate into the pressurizer during this postulated event. This results in a safety valve capacity that prevents system pressure from exceeding 110 percent of the system design pressure.

Pressurizer safety valve discharge is routed through a rupture disk to the containment atmosphere. The rupture disk is designed to contain any leakage past the safety valves and has a pressure rating much lower than the set pressure of the safety valve. Leakage past the safety valve during normal operation is collected and routed to the RCDT. Each safety valve discharge line includes a temperature indicator and alarm in the MCR.

Pressurizer safety valve discharge is directed away from the SSCs inside containment, which could be damaged by the discharge. The containment pressure resulting from a safety valve discharge is significantly less than the containment design pressure (the containment design pressure is determined by LOCA considerations), and the resulting heat load is well within the capacity of the normal fan coolers and the passive containment cooling system (PCS).

5.4.11.1 Automatic Depressurization System

DCD Tier 2, Figure 5.1-5 (sheet 1 of 3 and sheet 2 of 3), details the ADS. The system is not a pressure relief system. It is designed to depressurize the RCS under emergency plant operations and to vent noncondensable gases from the pressurizer steam space following an accident. Operation of the ADS valves is required for the PXS to function following postulated accident conditions. The first stage valves are used to vent noncondensable gases from the pressurizer steam space. In DCD Tier 2, Table 3.2-3 and Section 3.2, the applicant stated that the valves are classified as AP1000 equipment Class A (ANS safety Class 1), seismic Category I, and ASME Code Class 1. The valves are tested in accordance with the requirements of ASME Code, Section XI.

The ADS consists of 20 valves divided into 2 divisions, which are then further divided into 4 depressurization stages. These valves are connected to the RCS at three locations. The two divisions of the first-, second-, and third-stage valves are connected to the top of the pressurizer, while one division of the fourth-stage valves is connected to the hot leg of each

RCS loop and vents directly to an SG compartment. The fourth-stage valves are designed such that they cannot open against full system pressure.

The discharge from the first-, second-, and third-stage ADS valves is routed to the IRWST by way of two depressurization spargers (one per division). The spargers are classified as AP1000 equipment Class C (ANS safety Class 3) and seismic Category I, and are designed to distribute steam inside the IRWST to ensure effective steam condensation. The IRWST also receives discharges from the relief valve of the RNS, and steam and gas discharges from the PRHR high-point vents and the RV high-point vents (see DCD Tier 2, Section 5.4.12).

As described in DCD Tier 2, Sections 5.4.6 and 6.3, the ADS, consisting of four stages, is part of the RCS and interfaces with the PXS. Two valves are located in each discharge path to prevent inadvertent ADS valve discharges, should a valve accidentally open. Diverse and redundant features are provided in the ADS control system to ensure that valves do not inadvertently open. Following ADS actuation, steam can condense in the discharge line, creating a vacuum condition that could result in a reverse flow of water from the IRWST. To prevent this, vacuum breakers are provided in the discharge lines to limit the pressure drop that may occur following ADS actuation, thus preventing backflow.

5.4.11.2 In-Containment Refueling Water Storage Tank

The IRWST is a stainless steel-lined compartment inside containment that is integrated into the containment structure underneath the operating deck. The tank is classified as AP1000 equipment Class C (ANS safety Class 3) and seismic Category I. The tank is designed to absorb the pressure increase and heat input from the discharge of a first-stage ADS valve (including the water seal, steam, and gases) when the venting of noncondensable gases from the pressurizer occurs following an accident.

As stated above, the first-, second-, and third-stage ADS valves are divided into two divisions that connect to two separate spargers below the water level of the IRWST. The discharge from the spargers does not result in pressures in excess of the design pressure of the IRWST during a first-stage ADS valve discharge of steam, water, and noncondensable gases during an accident. In addition, the IRWST has covered vents that provide tank overpressure protection. The IRWST does not use a covered gas or a spray system, and does not have a connection to the waste gas processing system. The IRWST is cooled by the RNS and includes level and temperature indicators and alarms.

Conformance with GDC 2 is demonstrated by meeting the guidelines of Positions C.2 and C.3 of RG 1.29. Position C.2 states that those portions of the system whose function is not required, but whose failure could reduce the functioning of any seismic Category I system, or could incapacitate the occupants of the MCR, should be designed and constructed so that an SSE would not cause this failure. As stated above, the pressurizer relief discharge components are seismic Category I, and discharge is directed away from any safety-related SSCs inside containment that could be damaged by the discharge. Also, the discharges from the ADS valves are routed to the IRWST, which is designed to accommodate these discharges and, therefore, will not pose a hazard to nearby safety-related SSCs. These processes occur inside containment and, therefore, do not affect the MCR. In addition, the applicant has stated in DCD Tier 2, Appendix 1A, that the AP1000 design will conform to the guidelines of this position.

Position C.3 states that seismic Category I design requirements should extend to the first seismic restraint beyond the defined boundaries. Those portions of the system that form interfaces between seismic Category I and nonseismic Category I features should be designed to seismic Category I requirements. The applicant has stated in DCD Tier 2, Appendix 1A, that the system design will conform to the guidelines of this position.

The pressurizer safety valve discharge is directed away from safety-related SSCs inside containment that could be damaged by the discharge. In addition, discharges from the ADS valves are routed to the IRWST, which is designed to accommodate these discharges. On the basis of this information, the staff concludes that the pressurizer relief discharge equipment is adequately protected from the dynamic effects associated with failed SSCs inside containment, and will also not pose a hazard to other safety-related SSCs inside containment, should any of the pressurizer relief discharge equipment fail.

Based on the evaluation of information and commitments provided by the applicant in the DCD, the staff concludes that equipment used for the AP1000 pressurizer relief discharge meets the requirements of GDC 2 by conforming with Positions C.2 and C.3 of RG 1.29. This equipment also meets the requirements of GDC 4 because the safety-related SSCs will be protected from the effects associated with a failure of the equipment. Therefore, the staff concludes that the systems and components used for AP1000 pressurizer relief discharge conform to the appropriate guidelines of SRP Section 5.4.11 and, therefore, are acceptable.

5.4.12 Reactor Coolant System High-Point Vents

RCS high-point vents are provided to exhaust noncondensable gases accumulated in the primary system that could inhibit natural circulation core cooling. As required by 10 CFR 50.34(f)(2)(vi), the RCS must include high-point vents to maintain adequate core cooling, and the systems available to achieve this must be capable of being operated from the MCR. In addition, the operation of these systems must not lead to an unacceptable increase in the probability of a LOCA, or an unacceptable challenge to containment integrity.

In the AP1000 design, noncondensable gases from the RCS are vented using either a reactor head vent or, following an accident, the first-stage valves of the ADS connected to the pressurizer. In addition, the PRHR HX piping and the CMT inlet piping in the PXS also include a high-point vent and, therefore, are in compliance with 10 CFR 50.34(f)(2)(vi).

The staff performed its review of the AP1000 RCS high-point vent design in accordance with Section 5.4.12 of the SRP as discussed below.

5.4.12.1 <u>Reactor Vessel Head Vent System</u>

The RV head vent system (RVHVS) is designed to remove noncondensable gases or steam from the RCS, with a capacity to vent a volume of hydrogen at system pressure and temperature equivalent to approximately 40 percent of the RCS volume in 1 hour. The RVHVS is primarily used during plant startup to properly vent air from the RV head and to fill the RCS. The RVHVS valves also provide an emergency letdown path with a letdown flow rate within the capabilities of the normal makeup system to prevent pressurizer overfill following long-term loss of heat sink events.

The RVHVS consists of two parallel flow paths. Each contains two redundant, 2.54-cm (1-in.) open/close, solenoid-operated isolation valves in series and a flow-limiting orifice downstream. The system discharges to the IRWST.

The solenoid-operated isolation valves are fail-closed, normally closed valves, powered by the safety-related Class 1E dc and uninterruptible power supply system. The RVHVS is operated from the MCR, which has individual positive valve position indication and alarm. These valves are included in the AP1000 operability program with the IST requirements specified in DCD Tier 2, Table 3.9-16; they are qualified to Institute of Electrical and Electronics Engineers (IEEE)-323, IEEE-344, and IEEE-382.

The RVHVS is designed so that a single failure of the remotely operated vent valves, power supply, or control system does not prevent isolation of the vent path. The two redundant isolation valves in series minimize the possibility of RCPB leakage and ensure that the failure of any one valve does not inadvertently open a vent path.

The flow-limiting orifices limit the flow rate from the head vent path. Acceptance Criteria II.5 in Section 5.4.12 of the SRP specifies that the size of the vent line should be kept smaller than the size corresponding to the definition of a LOCA. This will avoid unnecessary challenges to the emergency core cooling system. Although the size of the vent pipe of 2.54 cm (1 in.) is larger than the size corresponding to the definition of a LOCA, the use of the orifices to restrict the flow rate of the head vent to within the capabilities of the normal makeup capability of the CVS allows the AP1000 to meet the intent of this criterion.

A break of the RVHVS line would result in a small-break LOCA no greater than 2.54 cm (1 in.) in diameter. Such a break is similar to the hot-leg break LOCA analyzed in DCD Tier 2, Section 15.6.5. The analysis results indicating no core uncovery also apply to a RVHVS line break.

The acceptance criteria of Section 5.4.12 of the SRP specify that procedures should be developed to use the vent paths to remove gases that may inhibit core cooling from the U-tubes of the SGs. In addition, the procedures to operate the vent system should consider when venting is needed and when it is not needed, taking into account a variety of initial conditions, operator actions, and necessary instrumentation. The applicant's response to RAI 440.049 describes the SG tube venting procedures.

During plant startup operations when the RV head is in place and the RCS is filled water solid, the air in the RCS is vented through repeated procedures of (1) starting an RCP in each SG for a short time with the high-point vents closed to allow collection of air in the RCS high points, and (2) opening the vents to allow air trapped in the high points to be vented. In addition to the normal venting procedures during startup, the AP1000 RVHVS could also be used under a design-basis accident scenario. During an accident, the AP1000 design relies on the passive safety-related systems, such as the PRHR HX, to provide the safety-related function of core cooling. Therefore, the design does not require the SG U-tubes to be vented to provide coolability of the core. However, the RVHVS is used under loss of heat sink events where the pressurizer level can increase and eventually become water solid, following long-term operation of the CMTs. To avoid this occurrence, the functional restoration guidelines for a high-pressurizer level in the ERG requires that the RV vent flow be established to provide a bleed path, in response to high-pressurizer level conditions, to reduce the RCS inventory and prevent pressurizer overfill. When the pressurizer level is sufficiently reduced, the operator recloses the head vent valves. In this case, the operator uses pressurizer level as the primary indication to control operation of the RV head vent.

The RV head vent system consists of safety-grade equipment. The piping and equipment from the vessel head vent up to, and including, the second solenoid valve constitute the RCPB, and are designed and fabricated to ASME Code Section III, Class 1, requirements. The remainder of the piping and equipment are designed and fabricated in accordance with ASME Code Class 3 requirements. The piping stresses meet the requirements of ASME Code, Section III, NC-3600, with a design temperature of 343.3 °C (650 °F), and a design pressure of 17.23 MPa (2485 psig). The RVHVS can be operated from the control room or the remote shutdown workstation. Each solenoid-operated isolation vent valve has a position sensor with indication in the control room. Inservice inspection and testing of the RVHVS is in accordance with DCD Tier 2, Section 3.9.6, for valves, and DCD Tier 2, Section 5.2.4, for ASME Code Class 1 components that are part of the RCPB. The RVHVS meets the acceptance criteria specified in Section II of Section 5.4.12 of the SRP and, therefore, is acceptable. Chapter 20 of this report addresses the resolution of TMI Action Item II.B.1.

5.4.12.2 <u>Automatic Depressurization System First-Stage Valves</u>

As discussed in Section 5.4.6 of this report, the first-stage valves of the AP1000 ADS provide the capability to remove noncondensable gases from the pressurizer steam space following an accident. Gas accumulations are removed by remote manual operation of the first-stage ADS valves. The discharge of the ADS valves is directed to the IRWST.

The ADS is primarily designed to function as a part of the PXS. The ADS piping up to, and including, the second isolation valve in series also constitutes the RCPB, and both the piping and valves are designed, constructed, and inspected to ASME Code Class 1 and seismic Category I requirements. The ADS valves are active valves required to provide safe shutdown or to mitigate the consequences of postulated accidents. However, venting of noncondensable gases from the pressurizer steam space is not required to provide safety-related core cooling following a postulated accident. Therefore, the acceptance guidelines of SRP Section 5.4.12 do not apply to the ADS.

5.4.12.3 <u>Passive Residual Heat Removal Heat Exchanger and Core Makeup Tank High-Point Vents</u>

The PRHR HX inlet piping and the CMT pressure balance line piping in the PXS include high-point vents that provide the capability to remove and prevent the accumulation of noncondensable gases that could interfere with the operation of the heat exchanger or CMT. These gases are normally expected to accumulate when the RCS is refilled and pressurized following refueling. Level indicators identify when gases have collected in the vent line. Any noncondensable gases that collect in this high point can be manually vented. The discharge of the PRHR HX high-point vent is directed to the IRWST, and the discharge of the CMT high-point vent is directed to the RCDT.

These high-point vent lines contain two manual isolation valves in series so that a single failure of either valve to reseat following venting operation does not prevent isolation of the flow path. The isolation valves in the vent line have position sensors with position indication in the MCR. Each vent line also contains a 0.95-cm (0.375-in.) flow restrictor, such that the break flow is within the makeup capability of the CVS and, therefore, would not normally require actuation of the passive safety systems. The vent lines downstream of the flow restrictors are 2.54-cm (1-in.) lines designed to ASME Code, Section III, Class 2, requirements. Inservice inspection of the PRHR HX and CMT high-point vents is in accordance with DCD Tier 2, Section 6.6, for ASME Code Class 2 components, and DCD Tier 2, Section 5.2.4, for ASME Code Class 1 components that are part of the RCPB. The staff concludes that the PRHR HX and CMT high-point vents are acceptable because they provide a means to prevent accumulation of noncondensable gases from the RCS that could interfere with operation of the PXS. Further, these high-point vents are designed in accordance with the ASME Code Section III requirements.

5.4.13 Core Makeup Tank

The AP1000 design includes two CMTs as part of the PXS. In the CMTs, cold borated water, under system pressure, is stored to provide high-pressure reactor coolant makeup and boration for LOCA and non-LOCA events, when the normal makeup system is unavailable or insufficient. DCD Tier 2, Section 6.3, describes the operation of the CMTs in the PXS and the connections to the CMTs.

5.4.13.1 Design Description

The AP1000 CMT is a low-alloy steel vessel with a minimum free internal volume of 70.75 m^3 (2500 ft^3). It is supported on columns. DCD Tier 2, Table 6.3-2, provides the CMT design data. The CMT injection line connects from one nozzle on the lower head to the RV DVI piping. The discharge line contains two normally closed, fail-open, parallel isolation valves, and two check valves in series. The CMT pressure balance line connects from the top nozzle in the center of the upper head to one of the RCS cold legs. The pressure balance line with the open flow path to the cold leg maintains system pressure. The top nozzle incorporates a diffuser inside the tank. The bottom of the diffuser, which has the same diameter and thickness as the connecting piping, is plugged and holes are drilled in the side to force the steam flow to turn 90 degrees. This limits the steam penetration into the coolant in the CMT. The diffuser is designed to reduce steam and hot water velocities entering the CMT, thereby minimizing potential water hammer and reducing the amount of mixing that occurs during initial CMT operation. Two sample lines in the upper and lower head, respectively, are provided for sampling the solution in the CMT. A fill connection is provided for makeup water from the CVS.

5.4.13.2 <u>Design Bases</u>

The CMT is a part of the RCPB and AP1000 Class A equipment, and is designed and fabricated according to ASME Code, Section III, Class 1 component requirements. Materials of construction are specified to minimize corrosion-erosion, and to provide compatibility with the operating environment, including the expected radiation level. DCD Tier 2, Section 5.4.13.4, states, and the staff agrees, that erosion is not an issue because there is normally no flow in the CMT. Those portions of the CMT in contact with reactor coolant are fabricated from or clad with stainless steel. Contamination of stainless steel and Ni-Cr-Fe alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited. Sections 5.2.3 and 5.2.4 of this report discuss the material selection and water chemistry specification, and the test and inspections of the CMT, respectively.

5.4.13.3 <u>Design Evaluation</u>

DCD Tier 2, Section 3.9.3, discusses the loading combinations, stress limits, and analytical methods for the structural evaluation of the CMT for various plant conditions. DCD Tier 2, Section 3.9.2, discusses the requirements for dynamic testing and analysis. The transients used to evaluate the CMT are founded on the system design transients described in DCD Tier 2, Section 3.9.1.1. In addition to normal RCS transients, the evaluation of the component cyclic fatigue of the CMT also assumes 30 occurrences in the plant's 60-year lifetime in which a small leak draws in hot RCS fluid, and 10 occurrences of increasing containment temperature above normal operating range.

DCD Tier 2, Sections 3.9.1, 3.9.2, and 3.9.3, respectively, discuss the mechanical component design evaluation with respect to the RCS design transients; requirements for dynamic testing and analysis; and loading combinations, stress limits, and analytical methods for structure evaluation. The staff's evaluation of these sections are discussed in the related sections of this report.

Chapter 6.3 of this report evaluates the functional performance of the CMTs, as part of the PXS performance, as well as the safety analyses of various design-basis transients and accidents described in Chapter 15 of this report, to demonstrate the capability of the CMTs to comply with the respective acceptance criteria. The staff has reviewed the PXS function performance and the design-basis analyses of transients and accidents, as described in Section 6.3 and Chapter 15 of this report. In addition, in support of the AP600 design certification application, the applicant performed various separate effects and integral system tests to study thermal-hydraulic behavior and the phenomena of the AP600 PXS and components, as well as to validate the codes used for the design-basis analysis of transients and accidents for the AP600. The same computer codes used for the AP600 were used for the AP1000 design. In Chapter 21 of this report, the staff discusses the applicability of the AP600 test program and computer codes to the AP1000 design. Because it finds the evaluations referenced above to be acceptable, the staff concludes that the CMT design meets the guidelines of SRP Section 6.3 and GDC 2, 4, 5, 17, 36, and 37. In addition, the staff finds that the PXS as a whole meets GDC 27, 34, and 35. Therefore, the CMT design is acceptable.

5.4.14 Passive Residual Heat Removal Heat Exchanger

The AP1000 PRHR HX is part of the PXS. Its function is to remove core decay heat for any postulated non-LOCA event in which a loss-of-cooling capability via the SGs occurs. Section 6.3 of this report discusses the operation of the PRHR HX in the PXS.

5.4.14.1 Design Description

The PRHR HX consists of a top and lower tube sheet mounted through the wall of the IRWST. A series of 1.9-cm (0.75-in.) outer diameter C-shaped tubes connect to the tube sheets, with the top of the tubes located several feet below the IRWST water surface. DCD Tier 2, Table 6.3-2, provides the AP1000 PRHR HX design data. An inlet channel head mounted to the top tube sheet is connected through piping to one of the RCS hot legs. An outlet channel head mounted to the bottom tube sheet is connected through piping to the SG cold-side channel head. The primary coolant passes through the tubes, transferring decay heat to the IRWST water. Sufficient thermal driving head is generated in the process to maintain natural circulation flow through the heat exchanger. The design minimizes the diameter of the tube sheets and allows ample flow area between the tubes in the IRWST. The horizontal lengths of the tubes and lateral support spacing in the vertical section allow for the potential temperature difference between the tubes in both cold and hot conditions. The PRHR HX is welded to the IRWST. The tubes are supported in the IRWST interior with a frame structure. The top of the structure supports a cover that traps and condenses steam during initial activation of the PRHR HX. This also helps to minimize the amount of humidity in containment.

5.4.14.2 Design Bases

The PRHR HX, in conjunction with the PCS, is designed to be able to automatically remove core decay heat for an unlimited period of time. This capability requires a closed-loop mode of operation where the condensate from steam generated in the IRWST is returned to the tank. The PRHR HX and the IRWST are designed to delay significant steam release to the containment for at least 1 hour. The PRHR HX will keep the reactor coolant subcooled and prevent water relief from the pressurizer. In addition, the PRHR HX will cool the RCS to 204.4 °C (400 °F) in 72 hours with RCPs operating or, if required, in the natural circulation mode, to allow the RCS to be depressurized to reduce stress levels in the system.

The PRHR HX is designed to withstand the design environment of 17.24 MPa (2500 psia) and 343.3 °C (650 °F) for 60 years. The PRHR HX is part of the RCPB, is designated AP1000 class A equipment, and is designed and fabricated according to the ASME Code, Section III, as a Class 1 component. DCD Tier 2, Section 5.2.3, discusses the material specifications and compatibility with the operating environment, including the expected radiation level, as well as the fabrication and processing of the stainless steel for the PRHR HX and the RCPB. Section 5.2.3 of this report provides the staff's evaluation of these issues. DCD Tier 2, Section 5.2.4, discusses the ISI and testing of Class 1 components, which are applicable to the PRHR HX.

5.4.14.3 Design Evaluation

DCD Tier 2, Sections 3.9.1 through 3.9.3 discuss the loading combination, stress limits, and analytical methods for evaluating the structural integrity of the PRHR HX, as well as the transients used to evaluate the PRHR HX under various plant conditions. During normal plant operation, the PRHR HX, without flow through it, is pressurized to the RCS hot-leg pressure at the IRWST temperature. Operation of the PRHR HX is evaluated using ASME, Section III defined Service Levels B, C, and D plant conditions, as described in DCD Tier 2, Section 3.9.1.1. In addition to loads resulting from normal RCS transients and the PRHR HX operation, the evaluation also considers hydraulic loads due to discharge of steam from the ADS valves into the sparger in the IRWST. Seismic, LOCA, sparger activation, and flow-induced vibration loads are derived using dynamic models of the PRHR HX. The dynamic analysis considers the hydraulic interaction between the coolant and system structural elements. The evaluation of component cyclic fatigue also assumes the following two additional Service Level B transients that affect only the PRHR HX:

(1) 30 occurrences in the plant's 60-year lifetime in which a small leak in the manway cover draws in hot RCS fluid

(2) 10 occurrences of increasing IRWST temperature as a result of an event that activates passive core cooling

Sections 3.9.1, 3.9.2, and 3.9.3, respectively, of this report discuss the staff's evaluation of the mechanical component design with respect to the design transients; requirements for dynamic testing and analysis; and loading combinations, stress limits, and analytical methods for structure evaluation.

Chapter 6.3 of this report evaluates the PRHR HX functional performance, as part of the PXS performance. Chapter 15 of this report presents the safety analyses of various design-basis transients and accidents to demonstrate the PXS capability to comply with applicable acceptance criteria. In addition, in support of the AP600 design certification application, the applicant had performed various separate effects and integral system tests to study the thermal-hydraulic behavior and the phenomena of the AP600 PXS and components, as well as to validate the codes used for the design-basis analysis of transients and accidents for the AP600. The same computer codes used for the AP600 are used for the AP1000 design. In Chapter 21 of this report, the staff discusses the applicability of the AP600 test program and the computer codes to the AP1000 design. Because it finds the evaluations referenced above to be acceptable, the staff concludes that the PRHR HX design meets the guidelines of SRP 6.3 and GDC 2, 4, 5, 17, 34, 36, and 37. Therefore, the PRHR HX design is acceptable.

6. ENGINEERED SAFETY FEATURES

6.1 Engineered Safety Features Materials

6.1.1 Structural Materials

The staff reviewed AP1000 Design Control Document (DCD), Tier 2, Section 6.1.1, "Metallic Materials," for engineered safety features (ESFs), in accordance with Section 6.1.1, "Engineered Safety Features Materials," of the Standard Review Plan (SRP). ESFs are provided in nuclear plants to mitigate the consequences of design-basis or loss-of-coolant accidents (LOCAs). General Design Criteria (GDC) 1, "Quality Standards and Record," GDC 4, "Environmental and Dynamic Effects Design Basis," GDC 14, "Reactor Coolant Pressure Boundary," GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," GDC 35, "Emergency Core Cooling," and GDC 41, "Containment Atmosphere Cleanup," of Title 10, Part 50, of the Code of Federal Regulations (10 CFR Part 50), Appendix A, "General Design Criteria for Nuclear Power Plants"; Appendix B, "Quality Assurance Criteria for Nuclear Power Plants," to 10 CFR Part 50; and 10 CFR 50.55a apply to ESF systems.

GDC 1 and 10 CFR 50.55a(a)(1) require that structures, systems, and components (SSCs) important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

GDC 4 requires that SSCs important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents (e.g., LOCAs).

GDC 14 requires that the reactor coolant pressure boundary (RCPB) shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

GDC 31 requires that the RCPB shall be designed with sufficient margin to assure that, when stressed under operation, maintenance, testing, and postulated accident conditions, it will behave in a nonbrittle manner and probability of rapidly propagating fracture is minimized.

GDC 35 requires a system to provide abundant emergency core cooling. GDC 35 also requires that during activation of the system, clad metal-water reaction be limited to negligible amounts.

GDC 41 requires that containment atmosphere cleanup systems be provided to control fission products, hydrogen, oxygen, and other substances that may be released into the reactor containment. The staff's review of the ESF structural materials was limited to ensuring that the requirements of GDC 41 were met with respect to corrosion rates as they relate to hydrogen generation to postaccident conditions.

Appendix B to 10 CFR Part 50 establishes the quality assurance requirements for the design, construction, and operation of those systems that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public.

Engineered Safety Features

This section provides a review of the materials used in the fabrication of ESF components and the need to avoid material interactions that could potentially impair the operation of the ESFs.

Summary of Technical Information

The ESFs identified in DCD Tier 2, Chapter 6 consist of the containment vessel, the passive containment cooling system (PCS), the containment isolation system (CIS), the passive core cooling system (PXS), the main control room emergency habitability system (VES), and the fission product system. DCD Tier 2, Section 6.1, describes the materials used in the fabrication of ESF components and of the provisions to avoid materials interactions that could potentially impair ESF operation for the AP1000 design.

DCD Tier 2, Table 6.1-1, "Engineered Safety Features Pressure-Retaining Materials," lists the material specifications for the principal pressure-retaining components. DCD Tier 2, Table 5.2-1, "Reactor Coolant Pressure Boundary Materials Specifications," lists the specifications for the core makeup tank (CMT), passive residual heat removal heat exchanger (PRHR HX) and valves in contact with borated water.

The materials for use in the ESF are selected for their compatibility with the reactor coolant system (RCS) and refueling water. The edition and addenda of the American Society of Mechanical Engineers (ASME) Code applied in the design and manufacture of each component are the edition and addenda established by the Design Certification. The baseline used for the DCD is the 1998 Edition, through the 2000 Addenda.

The pressure-retaining materials in ESF system components comply with the corresponding materials specifications permitted by the ASME Code, Section III, Division 1.

The components of the ESFs that are in contact with borated water are fabricated primarily from, or clad with, austenitic stainless steel or equivalent corrosion-resistant material. The use of nickel-chromium-iron (Ni-Cr-Fe) alloys in the ESFs is limited to Alloy 690/52/152.

Low- or zero-cobalt alloy hardfacing materials in contact with the reactor coolant are qualified by wear and corrosion tests for performance equivalent to Stellite-6. The use of cobalt-based alloys is minimized. Low- or zero-cobalt alloys used for hardfacing or other applications in which cobalt alloys have been previously used are qualified using wear and corrosion tests. Cobalt-free, wear-resistant alloys considered for this design include those developed and qualified in nuclear industry programs.

Austenitic stainless steel is used in the final heat-treated condition, as required by the respective ASME Code, Section II, materials specification for the particular type or grade of alloy. Austenitic stainless steel materials used in the ESF components are handled, protected, stored, and cleaned to minimize contamination that could lead to stress-corrosion cracking (SCC). These controls for ESF components are the same as those for ASME Code Class 1 components discussed in DCD Tier 2, Section 5.2.3.4. Sensitization avoidance, intergranular attack prevention, and control of cold work for ESF components are the same as the ASME Code Class 1 components discussed in DCD Tier 2, Section 5.2.3.4. Cold-worked austenitic stainless steels having a minimum specified yield strength greater than 620.5 MPa (90,000 psi) are not used for ESF components.

The material for the air storage tanks in the VES is controlled by ASME SA-372, "Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels." It is tested for Charpy-V notch energy in accordance with supplement S3 of materials specification ASME SA-372. The material is required by the applicant's material specification to have an average of 0.51 to 0.64 mm (20 to 25 mils) of lateral expansion at the lowest anticipated service temperature. The applicant's material specification prohibits weld repairs.

The majority of the ESF insulation used in the AP1000 containment is reflective metallic insulation. Fibrous insulation may be used if it is enclosed in stainless steel cans. The selection, procurement, testing, storage, and installation of nonmetallic thermal insulation provides confidence that the leachable concentrations of chloride, fluoride, and silicate are in conformance with Regulatory Guide (RG) 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel."

Evaluation

The staff's evaluation of the ESF materials is divided into the following four sections—(1) materials and fabrication, (2) composition and compatibility of ESF fluids, (3) component and systems cleaning, and (4) thermal insulation.

Materials and Fabrication

The staff reviewed DCD Tier 2, Section 6.1.1, for ESFs to determine the suitability of the materials for this application.

The components of the ESFs used in pressure-retaining situations are fabricated primarily from austenitic stainless steels or other corrosion-resistant material, such as Ni-Cr-Fe alloys. Where carbon steel is used in structures in contact with borated water, the steel is clad with austenitic stainless steel. Other types of protective coatings are applied to the surfaces of carbon steel structures not exposed to borated water or other fluids. Section 6.1.2 of this report reviews protective coatings. Valve seating surfaces are hardfaced to prevent failure and minimize wear.

The DCD states that the use of Ni-Cr-Fe alloy as a structural material in the ESFs will be limited to Alloy 690/52/152. The decision to use Alloy 690/52/152 was based on its improved performance in pressurized-water reactor (PWR) primary water. The staff believes the selection of Alloy 690/52/152 as the preferred nickel-based alloy is prudent because of its demonstrated improved resistance to SCC as compared to Alloy 600/82/182, which has been widely used for these applications in currently operating reactors.

Materials used in the fabrication of ESF components should be selected after consideration of the possibility of degradation during service. The materials selected for the ESF components exposed to the reactor coolant conform to Section III of the ASME Code, in particular Subarticles NB-, NC- and ND-2160, and NB-, NC- and ND-3120, as appropriate. Subarticles NB-, NC-, and ND-2160 are concerned with the deterioration of materials while in service, specifically with respect to changes in properties as distinct from loss of material. For example, valves and other components that may be made of cast austenitic stainless steel could deteriorate over time as a result of thermal embrittlement unless provisions are made to control the ferrite content. In the design of the AP1000 ESFs, the materials specifications for the pressure-retaining valves and piping in contact with the reactor coolant are the same as those used for the RCPB valves and piping. Section 5.2.3 of this report evaluates this information. In Section 5.2.3 of this report, the staff evaluated the acceptability of the RCPB materials with respect to the materials specifications, compatibility of the materials with the coolant environment, and the proposed fabrication processes. The staff concluded that the applicable NRC requirements were met.

The materials of ESF components comply with Subarticles NB-, NC-, and ND-3120 which require consideration of the effects of corrosion, erosion, and abrasive wear (Subarticles NB-, NC-, and ND-3121) and of environmental effects, specifically, irradiation-induced changes (Subarticles NB-, NC-, and ND-3124). DCD Tier 2, Section 6.1.1.2 refers to DCD Tier 2, Section 5.2.3, for discussion of the fabrication and processing of austenitic stainless steels and compliance to the regulatory positions of RG 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal"; RG 1.34, "Control of Electroslag Weld Properties"; RG 1.44, "Control of the Use of Sensitized Stainless Steel"; and RG 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel." DCD Tier 2, Section 6.1.1.2, describes the controls placed on cold work in austenitic stainless steels by reference to DCD Tier 2, Section 5.2.3.4. The methods to control delta ferrite content in austenitic stainless steel weldments in ESF components are the same as those for the ASME Code Class 1 components described in DCD Tier 2, Section 5.2.3.4. Section 5.2.3 of this report documents the staff's review of this section and the staff's review of conformance with the RGs noted above. DCD Tier 2, Section 6.1.3.1, states that "the Combined License [COL] applicants referencing the AP1000 will address review of vendor fabrication and welding procedures or other quality assurance methods to judge conformance of austenitic stainless steels with RGs 1.31 and 1.44." This is COL Action Item 6.1.1-1.

The materials selected for the AP1000 ESFs satisfy the applicable requirements of Section III of the ASME Code and Section II of the Code and therefore satisfy 10 CFR 50.55a and GDC 1. The fracture toughness of the ferritic materials will meet the requirements of the ASME Code. Cold-worked stainless steels meet the staff position that the yield strength of cold-worked stainless steels shall be less than 620.5 MPa (90,000 psi). The staff finds that the materials specifications and fabrication for the AP1000 design are acceptable and satisfy GDC 14 and 31 with regard to ensuring an extremely low probability of leakage, rapidly propagating failure, or gross rupture because they satisfy the requirements of the ASME Code and conform to the regulatory positions of the SRP and applicable U.S. Nuclear Regulatory Commission (NRC) RGs.

<u>Composition and Compatibility of ESF Fluids</u>

The staff reviewed DCD Tier 2, Section 6.1.1.4, "Material Compatibility with Reactor Coolant System Coolant and Engineered Safety Features Fluids," to determine the compatibility of the ESF components with the various environments. The ESF components are manufactured primarily of stainless steel or other corrosion-resistant material. Protective coatings are applied on carbon steel structures and equipment located inside the containment. Section 6.1.2 of this report reviews protective coatings.

Austenitic stainless steel plate conforms to ASME SA-240 and is confined to those areas or components which are not subject to a postweld heat treatment. Carbon steel forgings conform to ASME SA-350. Austenitic stainless steel forgings conform to ASME SA-182. Ni-Cr-Fe alloy pipe conforms to ASME SB-167. Carbon steel castings conform to ASME SA-352. Austenitic stainless steel castings conform to ASME SA-351.

In some postulated postaccident situations, the containment could be flooded with water containing boric acid. Exposure of austenitic stainless steel to this solution for any prolonged period may induce SCC. In the design of the AP1000, the potential for this is minimized by the release of trisodium phosphate (TSP) from the pH adjustment basket into the containment sump. This action is controlled so that the pH of the sump fluid rises to above 7.0 and is thus consistent with the guidance of the NRC SRP Branch Technical Position (BTP) Materials Engineering Branch (MTEB) 6-1, "pH for Emergency Coolant Water for PWRs," regarding protection of austenitic stainless steel from SCC. Hence, the design meets the requirements of GDC 14 for ensuring the low probability of abnormal leakage, rapidly propagating failure, or gross rupture of the RCPB boundary and safety-related structures.

DCD Tier 2, Section 6.1.1, indicated that DCD Tier 2, Section 6.2.5, contains the hydrogen production analysis for a postaccident analysis. However, this statement was incorrect because the AP1000 DCD does not contain a hydrogen generation analysis in anticipation of the NRC completion of a rule change that would eliminate the design-basis hydrogen accident. The draft safety evaluation report (DSER) stated that because this was not consistent with the current rule, the staff was not able to complete a review of the corrosion rates and consequent hydrogen generation. This was Open Item 6.1.1-1 in the Draft Safety Evaluation Report (DSER).

GDC 41 requires that containment atmosphere cleanup systems be provided, as necessary, to control fission products, hydrogen, oxygen, and other substances that may be released into reactor containment. The AP1000 design does not have a safety-related containment spray system. The staff's review of the ESF with respect to control of hydrogen production for postaccident conditions, and thus conformance with GDC-41, was pending resolution of DSER Open Item 6.1.1-1.

The Commission approved a final rule, effective October 16, 2003, amending 10 CFR 50.44 to eliminate the requirements for hydrogen recombiners and hydrogen purge systems in currently licensed light-water reactors (LWRs). The rule relaxes the requirements for hydrogen and oxygen monitoring equipment commensurate with the equipment's risk significance. The rule also specifies requirements for combustible gas control in future water-cooled reactors and non-water-cooled reactors.

The installation of recombiners and/or vent and purge systems previously required by 10 CFR 50.44(b)(3) was intended to address the limited quantity and rate of hydrogen generation that was postulated from a design-basis LOCA. The NRC found that this hydrogen release is not risk-significant. The rule removes the existing definition of a design-basis LOCA hydrogen release and eliminates requirements for hydrogen control systems to mitigate such a release at currently licensed nuclear power plants (NPPs) and at most future water-cooled reactors, including the AP1000. Therefore, the AP1000 is not required to perform a design basis accident hydrogen generation analysis. The applicant removed the reference in DCD Tier 2, Section 6.1.1 to a hydrogen production analysis for a post accident analysis because the hydrogen production analysis is no longer necessary. On this basis, Open Item 6.1.1-1 is resolved.

Section 6.2.5 of this report includes additional discussion related to this issue and conformance with GDC 41.

Cobalt-based alloys have limited use in the AP1000 design. In addition, cobalt-free or low-cobalt, wear-resistant alloys used in the AP1000 design are qualified by wear and corrosion tests, and include those developed and qualified in nuclear industry programs. Based on the qualification testing of these alloys and the assurance provided by performance of these or similar materials in current NPPs for this application, the staff finds the use of these alloys in the ESF design acceptable and compatible with the reactor coolant.

The materials selected for the ESFs have demonstrated satisfactory performance in operating NPPs and their selection is consistent with current practices. Corrosion is expected to be negligible on the basis of inservice observations and the results of extensive test programs. The neutron flux received by the ESF components will be sufficiently low that no irradiation-induced changes are expected. The staff finds that, given the materials selected and the chemistry controls during postaccident conditions, the ESF system should not be susceptible to SCC, and clad-metal reaction will be negligible as a result of exposure to reactor coolant and refueling water. Thus, the ESF components in the AP1000 design meet the requirements of GDC 4 and 35 and Appendix B to 10 CFR Part 50, regarding compatibility with environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs.

<u>Component and Systems Cleaning</u>

The staff reviewed the ESF structural materials to ensure that the requirements of Appendix B were met, as they relate to the establishment of measures to control the cleaning of material and equipment, in accordance with work and inspection instructions, to prevent damage or deterioration.

The AP1000 design conforms to RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," with an exception to the quality standard of the American National Standards Institute (ANSI) N45.2-1-1973 referenced in RG 1.37. The applicant referenced ASME Quality Standard NQA-2, rather than ANSI N45.2-1. The staff found this to be acceptable because the requirements of N45.2-1 have been updated and incorporated into ASME Quality Standard NAQ-2, which the staff considered an enhacement. Section 17.3 of this report discusses the staff's evaluation of quality assurance documents. The staff finds the provisions for component and systems cleaning acceptable because these provisions conform to the regulatory positions of RG 1.37, with the exception evaluated in Section 17.3 of this report. Thus, they satisfy the quality assurance requirements of Appendix B to 10 CFR Part 50.

Thermal Insulation

The type of thermal insulation used in the AP1000 containment will be predominantly reflective metallic. Any fibrous insulation used will be enclosed in stainless steel cans. The DCD further states that any nonmetallic thermal insulation used in the design of the AP1000 ESFs will be in conformance with RG 1.36 with regard to leachable concentrations of chloride, fluoride, and silicate ions. Such actions ensure that the potential is extremely low for failure of the austenitic stainless steel pressure boundary components because of SCC resulting from the presence of contaminants in the thermal insulation. The staff finds the thermal insulation used in the AP1000 design of the ESFs to be acceptable because it conforms to the regulatory positions in RG 1.36. Thus, the provision of the type of insulation specified satisfies GDC 14 and 31 by minimizing the potential for causing SCC and thereby ensuring, with respect to this failure mechanism, that the reactor coolant boundary(RCPB) and associated auxiliary systems will have an extremely low probability of leakage, rapidly propagating failures, or gross rupture.

Conclusions

The staff concludes that the AP1000 DCD specifications concerning the materials to be used in the fabrication of the ESFs are acceptable and meet the relevant requirements of GDC 1, 4, 14, 31, 35, and 41 of Appendix A to 10 CFR Part 50; Appendix B to 10 CFR Part 50; and 10 CFR 50.55a.

6.1.2 Protective Coating Systems (Paints)—Organic Materials

Protective Coating

The staff reviewed DCD Tier 2, Section 6.1.2.1, "Protective Coatings," in accordance with Section 6.1.2, "Protective Coating Systems (Paints)—Organic Materials," of the SRP. The protective coating systems are acceptable if the protective coatings applied to the inside and outside of the AP1000 containment meet the requirements of Appendix B to 10 CFR Part 50, with regard to the quality assurance requirements for the design, fabrication, and construction of safety-related SSCs. To meet the requirements of Appendix B to 10 CFR Part 50, an applicant can specify that the coating systems and their applications will meet the position of RG 1.54, Revision 1, July 2000, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." This RG references the quality assurance standards of the American Society for Testing and Materials (ASTM) D3843-00, "Selection of Test Methods for Coatings for Use in Light-Water Nuclear Power Plants"; ASTM D3911-95, "Evaluating Coatings Used in Light-Water Nuclear Power Plants at Simulated Design-Basis Accident (DBA) Conditions"; and ASTM D5144-00, "Standard Guide for Use of Protective Coating Standards in Nuclear Power Plants."

Summary of Technical Information

The AP1000 design divides protective coatings into the following four areas with respect to the use of the coatings:

(1) inside containment
(2) exterior surfaces of the containment vessel
(3) radiologically controlled areas outside containment
(4) remainder of plant

In addition, the AP1000 design addresses the classification of the coatings applied inside and outside containment in DCD Tier 2, Table 6.1-2, "AP1000 Coated Surfaces, Containment Shell and Surfaces Inside Containment," based on their functions and to what extent the coatings are safety-related.

Although the DCD references RG 1.54, Revision 1, it is structured around the guidance of the RG before it was revised. The RG originally characterized coatings in terms of safety-related or non-safety-related in various spaces of an NPP. DCD Tier 2, Appendix 1A, references RG 1.54, Revision 1, and provides a summary description of the exceptions to this RG. The AP1000 design designates some coatings inside containment as non-safety-related and discusses appropriate ASTM standards that will be met. In addition, the coatings are controlled by procedures using qualified personnel, and the non-safety-related coatings are subject to the quality assurance requirements of Appendix B to 10 CFR Part 50. The AP1000 design takes exception to the RG in that the degree of conformance with the RG will be a function of the program developed by the COL applicant. DCD Tier 2, Section 6.1.3.2, states that the COL applicant will provide a program for the control of the use of these coatings, consistent with DCD Tier 2, Section 6.1.2.1.6. This is COL Action Item 6.1.2-1.

Staff Evaluation

RG 1.54, Revision 1, provides guidance on practices and programs that are acceptable to the NRC staff for the selection, application, qualification, inspection, and maintenance of protective coatings applied in NPPs. In addition, this latest revision to the RG updates the definitions of Service Level I, II, and III coatings' locations to include both safety-related and non-safety-related regions, as set forth by the ASTM Committee and the updated ASTM guidance.

By letter dated September 24, 2002, the staff, in request for additional information (RAI) 281.001, requested the applicant to address how the AP1000 design incorporates RG 1.54, Revision 1, because the terms "safety-related" and "non-safety-related" are not used in this revision to classify coatings. In addition, the staff requested the applicant to clarify which of the coatings listed in DCD Tier 2, Table 6.1-2, meet the definitions of Service Levels I, II, and III. In its response dated December 2, 2002, the applicant stated that DCD Tier 2, Section 6.1, will be revised to be consistent with the coatings classifications and associated terminology introduced in RG 1.54, Revision 1. The staff reviewed the proposed changes to DCD Tier 2, Section 6.1, including Table 6.1-2, and determined that the applicant modified this section appropriately by incorporating the new guidance in the latest revision to RG 1.54. The applicant committed to meet the guidance in RG 1.54, Revision 1, as appropriate for each of the following three service levels:

(1) Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of postaccident fluid systems and thereby impair safety.

(2) Service Level II coatings are used in areas where coatings failure could impair, but not prevent, normal operating performance. The functions of Service Level II coatings are to provide corrosion protection and decontaminability in those areas outside the reactor containment that are subject to radiation exposure and radionuclide contamination. Service Level II coatings are not safety-related.

(3) Service Level III coatings are used in areas outside the reactor containment where failure could adversely affect the safety function of a safety-related SSC.

The staff reviewed the COL item in DCD Tier 2, Section 6.1.3.2, and found it acceptable because the COL coatings program will conform to the NRC-accepted practice in RG 1.54, Revision 1.

Conclusions

The staff concludes that the protective coatings and their applications are acceptable and meet the requirements of Appendix B to 10 CFR Part 50. This conclusion is based on the applicant having met the quality assurance requirements of Appendix B to 10 CFR Part 50 through its commitment to RG 1.54, Revision 1. By meeting the recommendations in RG 1.54, Revision 1, the COL applicant will have evaluated the suitability of the coatings to withstand a postulated design-basis accident (DBA) environment, in accordance with NRC-accepted practices and procedures.

6.2 Containment Systems

The containment systems for the AP1000 design consist of the following three components:

(1) a steel vessel as the primary containment

(2) a shield building surrounding the primary containment which provides external missile protection and is also a principal component of the PCS

(3) supporting systems

The primary containment prevents the uncontrolled release of radioactivity to the environment and acts as the passive safety-grade interface to the ultimate heat sink.

The primary containment has a design leakage rate of 0.10 weight percent per day of the original containment air mass per day following a DBA. This value is determined by the containment design pressure of 508.12 kPa (59 psig). The limiting calculated peak pressure occurs for a double-ended, guillotine break in the RCS cold-leg LOCA, and is 499.84 kPa (57.8 psig).

As the interface to the ultimate heat sink (the surrounding atmosphere and external cooling water), the primary containment is an integral component of the PCS described in Section 6.2.2 of this report. The exterior of the containment vessel provides a surface for evaporative film cooling and works in conjunction with the natural draft airflow created by the shield building baffle and chimney arrangement to reduce the pressure and temperature of the containment atmosphere following a DBA.

6.2.1 Primary Containment Functional Design

The AP1000 primary containment consists of a 39.62-m- (130-ft-) diameter cylindrical steel shell with ellipsoidal upper and lower heads and a nominal wall thickness of 4.45 cm (1.75 in.). The wall thickness is increased to 4.76 cm (1.875 in.) in the transition region where the cylindrical shell enters the concrete embedment to provide a margin against corrosion. The wall thickness is also increased near primary containment penetrations to structurally compensate for these openings. The primary containment will enclose the nuclear steam supply system (i.e., reactor vessel, steam generators (SGs), reactor coolant pumps (RCPs), pressurizer, and associated connecting piping), the in-containment refueling water storage tank (IRWST), the CMTs, the accumulator tanks, and the refueling canal. Additionally, the primary containment houses associated mechanical support components; electrical support components; and heating, ventilation, and air conditioning (HVAC) support components.

The primary containment shell is supported by embedding the lower head between the concrete of the containment internal structures and the concrete encasement external to the containment vessel. No structural connection exists between the free-standing portion of the containment and the adjacent structures, other than penetrations and their supports, and the supports for the baffle wall of the PCS. Thus, the portion of the cylindrical primary containment shell above the support region elevation of 30.48 m (100 ft) is structurally independent.

The primary containment has a net free volume of 58,333 m^3 (2,060,000 ft^3) and is designed to withstand pressures and temperatures resulting from a spectrum of primary coolant and steamline pipe breaks. The primary containment design parameters consist of an internal design pressure of 508.12 kPa (59 psig) and a design temperature of 149 °C (300 °F).

The following AP1000 containment design features are compared to those of the AP600 design in Table 6.2-1 of this report:

- containment structure type
- power level
- containment free volume
- design pressures
- design temperatures
- calculated peak DBA containment pressures and temperatures
- heat removal systems

- hydrogen control systems
- containment penetrations

Table 6.2-1 Comparison of AP600/AP1000 Containment Design Features

Parameter	AP600	AP1000
Power, Megawatt thermal (MWt)	1940	3400
Type of containment structure	4.1-cm- (1.625-in.-) thick steel cylindrical primary containment with top and bottom dome, surrounded by concrete shield building	4.45-cm- (1.75-in.-) thick steel cylindrical primary containment with top and bottom dome, surrounded by concrete shield building
Secondary containment	No	No
Free volume	4.9 E+4 m^3 (1.73E+6 ft^3)	5.8 E+4 m^3 (2.06E+6 ft^3)
Volume-to-power ratio	25.2 m^3/MW (892 ft^3/MW)	17.2 m^3/MW (606 ft^3/MW)
Internal design pressure	411.6 kPa (45 psig)	508.12 kPa (59 psig)
External design pressure	20.7 kPa (3.0 psid)	20 kPa (2.9 psid)
Design temperature	138 °C (280 °F)	149 °C (300 °F)
Design leak rate, weight %/day	0.10	0.10
Calculated peak internal pressure (design margin)	405.4 kPa (44.1 psig) (1.5%)	499.84 kPa (57.8 psig) (1.6%)
Calculated peak external pressure (design margin)	13.8 kPa (2.0 psid) (33%)	16.6 kPa (2.4 psid) (17%)
Heat removal system	PCS and non-safety-grade fan coolers	PCS and non-safety-grade fan coolers
Combustible gas control system	(1) DBA—passive autocatalytic recombiners (2) severe accidents—hydrogen igniters	(1) Defense-in-depth—passive autocatalytic recombiners (2) severe accidents—hydrogen igniters
Number of penetrations	~40	~40

Parameter	AP600	AP1000
Motive power for containment isolation valves	(1) air-operated valves (2) Class 1E dc motor-operated valves	(1) air-operated valves (2) Class 1E dc motor-operated valves

Section 15.3 of this report describes the staff's evaluation of the ability of the AP1000 design to comply with the relevant dose limits of 10 CFR 50.34 and GDC 19, "Control Room." That evaluation assumed a 0.10 weight percent per day leak rate from the AP1000 containment. Operating plants have demonstrated the ability to verify a design leak rate as low as 0.10 weight percent per day. Therefore, the staff finds that a design leak rate of 0.10 weight percent per day is acceptable for the AP1000.

The AP1000 design does not have safety-related containment sprays, which makes natural deposition on surfaces in containment far more important than in past designs. The design does include non-safety-related containment sprays, as described in DCD Tier 2, Section 6.5.2, and evaluated by the staff in Section 19.2.3.3.9 of this report.

Section 6.2.1.1 of this report discusses the containment design pressure margin. The design capability of the AP1000 for external pressure is 20 kPa (2.9 psid). Westinghouse calculated a peak external pressure of 16.6 kPa (2.4 psid).

The reliance of the AP1000 on cooling by naturally occurring physical phenomena represents a significant difference from designs for currently operating reactors. The heat removal system for the AP1000 containment is the PCS, which is described in detail in Section 6.2.2 of this report. A principal feature of the system is that it relies on gravity-driven flow and natural circulation to perform its cooling function. Previously licensed Westinghouse plants use containment sprays and fan coolers, which rely on active components (i.e., pumps and fans) to function.

The AP1000 has nonsafety, passive autocatalytic recombiners, as described in DCD Tier 2, Section 6.2.4, to provide for defense-in-depth protection against the buildup of hydrogen following a LOCA. Section 6.2.5 of this report includes the staff's evaluation of the combustible gas control.

Table 6.2-1 of this report also shows that the AP1000 containment has considerably fewer mechanical penetrations (approximately 40) than a typical two-loop design (approximately 100). Additionally, the containment isolation valves in the AP1000 are primarily either air operated or motor operated from a safety-grade direct current (dc) power source. In previous designs, containment isolation valves were typically motor-operated valves (MOVs) powered from safety-grade alternating current (ac). Section 6.2.4 of this report contains the staff's evaluation of the CIS.

Compliance with Regulatory Requirements

The Westinghouse AP1000 containment evaluation model is based on assumptions that maximize the initial stored energy within containment and minimize the rate of heat transfer from containment. The approach is consistent with the guidance provided in SRP Section 6.1.1.2.A, "PWR Dry Containments, Including Subatmospheric Containments." Westinghouse uses the WGOTHIC 4.2 computer program to evaluate the containment performance. Chapter 21 of this report provides a review of WGOTHIC 4.2 and the model used to evaluate containment performance.

Compliance with Appendix A to 10 CFR Part 50

Section 6.2 of the SRP delineates the current guidance for demonstrating that a containment design complies with GDC 16, "Containment Design," GDC 38, "Containment Heat Removal," and GDC 50, "Containment Design Basis." The SRP addresses acceptance criteria and some specific model assumptions for design-basis LOCA and main steamline break (MSLB) analyses for all existing containment types. Westinghouse elected to evaluate the PCS performance using these current guidelines. The Westinghouse documentation for the AP1000 evaluation model is consistent with the guidelines in SRP Sections 6.2.1 and 6.2.1.1.A, as well as RG 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants." Westinghouse also uses approved methods for the LOCA and MSLB mass and energy releases, and follows the guidance provided in SRP Sections 6.2.1.3 and 6.2.1.4, respectively.

Peak Pressure Criteria (GDC 16 and 50)

Acceptance criteria for existing containments include a margin between the design pressure and a conservatively calculated peak accident pressure. NUREG-0800, Section 6.2.1.1.A states that the margin should vary from 10 percent at the construction permit (CP) stage to a peak calculated pressure "less than the containment design pressure" at the operating license (OL) stage. Thus, even in instances in which much data and information are known and the staff possesses an independent, confirmatory calculational capability, a 10-percent margin was expected at the CP stage to cover uncertainties in meeting the requirements of GDC 16 and 50 following final construction (i.e., at the OL stage).

For the AP1000 containment, Westinghouse proposed a criterion that the calculated peak accident pressure not exceed the design pressure (a zero-margin criterion). In meeting this criterion, Westinghouse stated that it uses a conservative approach consistent with current staff guidelines. For design certification, under 10 CFR Part 52, the staff does not necessarily need the same demonstration of margin as normally expected at the CP stage. An appropriate initial test program, combined with appropriate inspections, tests, analyses, and acceptance criteria (ITAAC), is in place to assure that the assumptions and performance characteristics of the AP1000 containment and the PCS, as used in the licensing analyses, are verified prior to operation. Therefore, the staff finds the applicant's approach to be acceptable.

The staff reviewed the differences between the AP600 and the AP1000 to assure that the WGOTHIC 4.2 computer program and evaluation model are applicable to the AP1000. This review included the modeling assumptions, the treatment of stratification and circulation, and the applicability of the AP600 phenomena identification and ranking table (PIRT), scaling and testing program, and the applicability of the mass and heat transfer correlations for the larger AP1000. Chapter 21 of this report documents the staff's review.

The staff has determined that the WGOTHIC 4.2 computer program, combined with the conservatively biased evaluation model described in WCAP-15846, Revision 1, "WGOTHIC Application to AP600 and AP1000," is acceptable for the evaluation of the peak containment pressure following a DBA for the AP1000 design, as discussed in Chapter 21.6 of this report. Although the WGOTHIC 4.2 code itself is essentially a best-estimate tool, Westinghouse has taken a conservative approach in the evaluation methodology it is using to support design certification. The AP1000 WGOTHIC evaluation model uses appropriately conservative input values and applies conservative multipliers on the correlations used for PCS heat and mass transfer. Conservative models are used in the AP1000 WGOTHIC evaluation model to address the following areas:

- lumped-parameter network representation
- noncondensible circulation and stratification
- PCS flow and heat transfer models
- dead-ended and liquid-filled compartments

During the peak pressure period (up to about 2400 seconds for a LOCA, and up to about 1000 seconds for an MSLB), these conservatisms compensate for the uncertainties introduced by the use of passive safety features, leading to an overall conservative result for the calculated peak containment pressure.

Long-Term Pressure Analysis (GDC 38)

The objective of the long-term pressure analysis is to demonstrate that the containment design conforms to the requirements of GDC 38, which requires containment temperature and pressure be maintained at acceptably low levels following any LOCA.

In Item II.b of Section 6.2.1.1.A of the SRP, the staff guidance used to evaluate compliance with GDC 38, is that the containment pressure should be reduced to less than 50 percent of its peak value within 24 hours of the occurrence of a design-basis LOCA. This assures that the containment leak rate used for the siting evaluation is consistent with the design basis analysis assumption. Westinghouse proposed that the calculated pressure reduction be based on 50 percent of the design pressure to be consistent with current guidelines related to GDC 38. The staff found this approach acceptable because the peak calculated pressures are near the design value.

The Westinghouse analytical procedure can credit the effect of two-dimensional (2-D) heat conduction (between wet and dry regions of the containment shell) when less than full PCS water coverage of the containment shell is expected. The procedure was first presented in May 1997 (Westinghouse letter NSD-NRC-97-5152, "AP600 Design Changes to Address Post 72-Hour Actions," Attachment 2 - Description of method to account for circumferential (2-dimensional) conduction through the steel containment shell for containment pressure analyses, dated May 23, 1997), and discussed at an Advisory Committee on Reactor

Safeguards (ACRS) meeting in December 1997 (Westinghouse letter NSD-NRC-97-5492, "Presentation Material for December 9, 10, 11 and 12, 1997 ACRS, Meeting," dated December 17, 1997). Westinghouse did not identify, or at least account for, the need to consider 2-D heat transfer for the long-term containment pressure response when the PCS flow rate decreases after the passive containment cooling water storage tank (PCCWST) water level drops below 6.19 m (20.3 ft) in the selection of the analysis methodology (GOTHIC) and in the development of a model for the PCS (WGOTHIC). With the coverage area less than the initial assumed 90 percent, heat transfer from the hot, dry regions of the shell into the cooler, wet regions of the shell would occur. To account for this modeling deficiency, Westinghouse performed an ancillary calculation to credit more PCS water in the evaporation process, effectively generating a correction factor, and applied it to the limited PCS flow model.

The staff evaluated this ancillary calculation, and the staff believes that there is a real effect from 2-D heat conduction. However, as an insufficient amount of test data is available to validate this model, the staff is unable to determine how much credit should be given in evaluating the AP1000 design performance after 24 hours when 2-D heat conduction is included in the analysis. Therefore, the results from a WGOTHIC analysis that includes the 2-D heat conduction enhancement to the evaporation limited flow model may not be used to demonstrate reduced containment leakage after 24 hours when performing dose assessments, as described in DCD Tier 2, Section 15.6.5.3.3.

The 2-D enhancement to the Evaporation Limited flow model may not be used to credit leakage reduction for siting evaluations. A separate analysis may be performed for the limiting LOCA without 2-D conduction, and included in DCD Tier 2 Section 6.2.1.1.3, "Design Evaluation." This separate analysis may be used to confirm the assumption used in DCD Tier 2, Section 15.6.5.3.3 of reducing the containment leakage to half its design value after 24 hours.

After the peak pressure period, the uncertainty in the treatment of heat transfer processes continues to increase. These uncertainties, resulting from the evaluation model treatment of non-condensable circulation and stratification and the effectiveness of the PCS cooling at a reduced flow rate, are difficult to quantify using the available test data. Nevertheless, the heat removal capability of the AP1000 PCS (as calculated by the WGOTHIC Evaluation model) is sufficiently greater than the decay power to conclude that the containment pressure will decrease. The WGOTHIC analyses demonstrate the effectiveness of the PCS to reduce the containment pressure and maintain that pressure below the design limit. The system safety function to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any LOCA and maintain them at acceptably low levels has been demonstrated.

The applicant credits containment pressure reduction when performing dose assessments for siting evaluations. Therefore, a separate analysis was performed for the limiting LOCA without 2-D conduction, as discussed in DCD Tier 2, Section 6.2.1.1.3. This separate analysis confirmed the assumption used in DCD Tier 2, Section 15.6.5.3.3 of reducing the containment leakage to half its design value after 24 hours.

Compliance with 10 CFR 52.47(b)(2)

The unique characteristics of the PCS are explicitly recognized in the regulations governing the evaluation of standard plant designs. As stated in 10 CFR 52.47(b)(2)(i)(A), in the absence of a prototype plant that has been tested over an appropriate range of normal, transient, and accident conditions, the following requirements must be met for a plant that "utilizes simplified, inherent, passive, or other innovative means to accomplish its safety functions":

(1) The performance of each safety feature of the design has been demonstrated through either analysis, appropriate test programs, experience, or a combination thereof.

(2) Interdependent effects among the safety features of the design have been found acceptable by analysis, appropriate test programs, experience, or a combination thereof.

(3) Sufficient data exist on the safety features of the design to assess the analytical tools used for safety analyses over a sufficient range of normal operating conditions, transient conditions, and specified accident sequences, including equilibrium core conditions.

Consistent with these requirements, the passive plant vendor, Westinghouse, developed and performed design certification tests of sufficient scope, including both separate-effects and integral-systems experiments, to provide data with which to assess the computer programs used to analyze plant behavior over the range of conditions described in item 3 above.

To satisfy the requirements of 10 CFR 52.47(b)(2)(i)(A), Westinghouse developed test programs to investigate the passive containment safety systems. These programs included both component and phenomenological (separate-effects) tests and integral-systems tests. The cold water distribution test was a full-scale representation of the PCS flow characteristics. Additional separate-effects tests have been performed to extend the range of existing mass and heat transfer correlations used in the analysis codes, to comply with the last of the three requirements above.

The large-scale test (LST) is the only integral test for the PCS. Because this test facility exhibited a number of shortcomings in scaling and prototypicality, the LST data was not used in an integral mode. Instead, the LST data was used in a separate-effects mode to demonstrate the conservatism of portions of the evaluation model. The staff concludes that sufficient data has been provided to establish that the evaluation model is conservative at the scale of the AP1000.

The staff agrees with the Westinghouse PIRT conclusions that the difference between the AP600 and the AP1000 does not change the ranking of the phenomena, that no new phenomena have been identified, and that the models developed to address the high- and medium-ranked phenomena for the AP600 remain applicable for the AP1000 (see Chapter 21 of this report). The staff also agrees with the Westinghouse conclusion that the mass and heat transfer correlations are acceptable for the evaluation of the AP1000, and that the AP600 test program adequately covers the expected ranges for which these correlations are used (see Chapter 21 of this report).

The staff concludes that the evaluation model contains sufficient conservatisms, including factors to compensate for shortcomings in the LST, to accept WGOTHIC, in combination with the evaluation model for DBA licensing analyses to support design certification, as discussed in Chapter 21 of this report. Section 21.6.5.8.3 of this report defines the calculational method that has been reviewed by the staff and found acceptable with respect to the SRP 6.2.1 Section IV, "Evaluation Findings," item 1d finding. For any future licensing analyses, the AP1000 nodal model described in Section 13 of WCAP-15846, Revision 1, "WGOTHIC Application to AP600 and AP1000," should be used. Further, the assumptions should be consistent with the limitations and restrictions denoted in Section 21.6.5.8.3 of this report. As discussed above, the 2-D enhancement to the Evaporation Limited flow model may not be used to credit leakage reduction for siting evaluations. A separate analysis may be performed for the limiting LOCA without 2-D conduction, and included in DCD Tier 2, Section 6.2.1.1.3. This separate analysis may be used to confirm the assumption used in DCD Tier 2, Section 15.6.5.3.3 of reducing the containment leakage to half its design value after 24 hours.

6.2.1.1 Containment Pressure and Temperature Response to High-Energy Line Breaks

The staff reviewed the temperature and pressure response of the primary containment to a spectrum of LOCAs and MSLBs, and completed a review of the minimum containment backpressure for LOCA analyses. Westinghouse did not analyze the response of the shield building because this structure is vented to the atmosphere and is not designed to maintain a set pressure under LOCA or MSLB conditions.

The Containment Analytical Model

Westinghouse calculated the short- and long-term pressure and temperature response of the containment using the WGOTHIC computer code in the lumped-parameter mode. WGOTHIC is a program for modeling multiphase flow. It solves the conservation equations, in integral form, for mass, energy, and momentum for multicomponent flow. The momentum conservation equations are written separately for each phase in the flow field (drops, liquid pools, and atmosphere vapor). The following terms are included in the momentum equation:

- storage
- convection
- surface stress
- body force
- boundary source
- phase interface source
- equipment source

In creating the WGOTHIC 4.2 computer program, used for licensing analyses to support the design certification, from the GOTHIC computer program, Westinghouse added analytical models to represent the unique features of the AP1000 containment. Major additions included modeling the condensation heat transfer in the presence of noncondensible gases on the interior wall of the containment, one-dimensional heat conduction through the containment wall, and heat rejection on the exterior of the containment shell via evaporative cooling, natural convection cooling, and radiative cooling.

Design features of the PCS to address post-72 hour actions, in response to the staff requirements memorandum (SRM) dated January 15, 1997, relating to SECY-96-128, "Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," have been incorporated into the AP1000 design. These include an on-grade PCS auxiliary water storage tank and two recirculation pumps that provide the required makeup flow to the PCCWST from the auxiliary tank for the post-72 hour period (up to 7 days). In addition, the PCCWST also provides makeup to the spent fuel pool and for fire protection.

Table 6.2-2 of this report provides the initial conditions of pressure, temperature, humidity, and net containment free volume used for the DBA analyses.

Table 6.2-2 Containment Initial Condition

Parameter	Initial value	
Internal Temperature	48.9 °C	120 °F
Pressure	108.2 kPa	15.7 psia
Relative Humidity	0 %	0 %
Net Free Volume	58,333 m^3	2.06E+6 ft^3
External Temperature	46.1 °C dry bulb 26.7 °C wet bulb	115 °F dry bulb 80 °F wet bulb

The current initial internal pressure and temperature, and the external temperature are technical specifications (TS) maximums and have been shown, in Section 5 of WCAP-15846, Revision 1, to result in a conservative peak pressure calculation. It was also shown that zero percent relative humidity is a conservative assumption. The staff has reviewed these input assumptions and finds them acceptable because they maximize the calculated peak containment pressure, consistent with the guidance in SRP Section 6.2.1.1.A.

Table 6.2-3 of this report provides the PCS flow rates and surface area coverage used for the DBA safety analyses (from DCD Tier 2, Table 6.2.2-1).

Table 6.2-3 PCS Flow Rates and Area Coverage

PCCWST Water Elevation		Safety Analysis Flow Rate		Area Coverage
ft	m	Liters/min	gpm	% of circumference
27.5	8.38	1775.7	469.1	90
24.1	7.35	857.8	226.6	90
20.3	6.19	667.4	176.3	72.9
16.8	5.12	545.9	144.2	59.6
(Note)		381.2	100.7	41.6

Note: from passive containment ancillary water storage tank, at 72 hours.

WGOTHIC models the passive heat sinks in the containment, one-dimensional heat transfer through the containment vessel, evaporation of cooling water from the exterior of the containment vessel, and radiative and natural convection heat transfer in the shield building annulus. 2-D conduction can be considered in WGOTHIC 4.2 analysis to account for heat transfer between wet and dry regions of the containment shell for the long-term pressure response, when the PCS water coverage fraction is reduced as a result of lower PCS water delivery rates, as shown in Table 6.2-3 of this report. The passive heat sinks include both concrete and steel structures inside the containment, which can absorb energy from the containment atmosphere. The energy source is modeled using information from a table of mass and energy releases included in DCD Tier 2, Sections 6.2.1.3 and 6.2.1.4.

Containment Pressure Response

The staff has reviewed the Westinghouse analyses of the pressure response of the AP1000 containment, as discussed below.

Internal Pressure Analysis

The pressure response of the AP1000 containment can be divided into two temporal phases—the short-term or blowdown portion of the transient, and the longer term representing the remainder of the transient. The AP1000 containment response to the high-pressure blowdown portion of LOCA and MSLB transients is not significantly different from that of a standard Westinghouse two- or three-loop plant. Blowdown is the time during which the contents of the coolant system are expelled through a postulated break. During blowdown, the large time constant for heat transfer through the containment shell causes the AP1000 containment response to be governed primarily by the energy absorbed by pressurizing the internal containment volume and by heat removal via internal structures (heat sinks). Therefore, the predicted containment response during the blowdown phase should be similar to that for a standard Westinghouse two- or three-loop plant. None of the new AP1000 passive design features come into play during this first portion of a postulated transient. In Section 8 of WCAP-15846, Revision 1, Westinghouse performed an analysis during the blowdown portion of the LOCA to compare the current multinode model to a simple, single-node model (similar to the modeling used for currently operating reactors). This analysis showed that the multinode model during blowdown yields results comparable to the simple, single-node model.

The long-term portion of the transient begins after the coolant system has blown down. During this time, the mass and energy releases are greatly reduced, and the PCS begins operating and transferring energy stored inside the containment to the ultimate heat sink. The primary mechanism of heat removal from inside the containment is the condensation of steam on the inside of the containment shell. This heat is ultimately rejected to the environment by means of radiative, convective, and evaporative cooling from the containment outer surface.

For the LOCA events, two limiting, double-ended guillotine RCS pipe breaks are analyzed. In one case, the break is postulated to occur in the hot-leg of the RCS; in the other case, the break is in the cold-leg. The hot-leg break results in the highest blowdown peak temperature. The cold-leg break results in the highest postblowdown peak pressure. The cold-leg break analysis includes the long-term contribution to containment pressure from the sources of stored energy, such as the SGs. Section 6.2.1.3 of this report discusses the LOCA mass and energy release calculations.

For the MSLB event, a representative pipe break spectrum is analyzed. The WGOTHIC 4.2 code is used to analyze various break sizes, power levels, and failure assumptions. Section 6.2.1.4 of this report discusses the MSLB mass and energy release calculations.

Table 6.2-4 of this report provides a summary of the calculated pressures and temperatures for LOCA and MSLB postulated accidents.

Table 6.2-4 Summary of Calculated Pressures and Temperatures for a LOCA and an MSLB Using WGOTHIC 4.2

Break	Peak Pressure [kPa (psig)]	Available Margin[1] [kPa (psig)]	Peak Temperature[2] [°C (°F)]	Pressure at 24 hours [kPa (psig)]
LOCA, double-ended, hot-leg guillotine	446.06 (50.0)	62.05 (9.0) 12.2%	213.6 (416.5)	---
LOCA, double-ended, cold-leg guillotine	499.84 (57.8)	8.27 (1.2) 1.6 %	140.5 (284.9)	253 (22)[3]
MSLB, 0.13 m^2 (1.4 ft^2), full double-ended rupture (DER), 101% power, MSIV failure	471.57 (53.7)	36.5 (5.3) 7.2%	190.7 (375.3)	---
MSLB, 0.13 m^2 (1.4 ft^2), full DER, 30% power, MSIV failure	496.39 (57.3)	11.7 (1.7) 2.3%	189.9 (373.9)	---

Notes: 1. design pressure is 508.12 kPa (59 psig), margin determined by absolute pressure
2. localized temperature in the break compartment (node)
3. Value includes 2-D multiplier. A separate analysis was performed without the 2-D multiplier to confirm the pressure at 24 hours was less than half the design value. Without the 2-D multiplier the pressure was calculated to be 26.5 psig.

The maximum calculated pressure in the primary containment occurs from a double-ended, guillotine break in the RCS cold-leg LOCA, and is 499.84 kPa (57.8 psig) at about 1800 seconds after the LOCA begins. This value provides a margin of 1.6 percent to the design pressure of 508.12 kPa (59 psig).

The WGOTHIC 4.2 containment evaluation model was created using assumptions that maximize the initial stored energy within containment and minimize the rate of heat transfer from containment. A summary of the conservatisms Westinghouse identified by the AP1000 WGOTHIC 4.2 containment evaluation model is as follows:

- The mass and heat transfer coefficients on the inner containment vessel surface are multiplied by a factor of 0.73. Only free convection is considered on the inner surface. The multiplier was determined by an assessment of the LST and separate tests, as discussed in Section 21.3.4 of this report.

- The mass and heat transfer coefficients on the outer containment vessel surface are multiplied by a factor of 0.84. Mixed convection is considered on the outer surface. The multiplier was determined by an assessment of the LST and separate tests, as discussed in Section 21.3.4 of this report.

- The vessel wall emissivity values are reduced by 10 percent to reduce the radiation heat transfer.

- The maximum outside air temperature of 46 °C (115 °F) is used as a boundary condition to reduce the heat transfer from containment and is consistent with the TS maximum allowable ambient temperature.

- The maximum containment air temperature of 49 °C (120 °F) and internal pressure of 108.2 kPa (1 psig) are used as initial conditions and are consistent with the TS limits. An initial condition of zero percent humidity is used to increase the initial stored energy inside containment.

- A single failure of one out of three valves controlling the PCS cooling waterflow is assumed. This assumption provided the minimum PCS liquid filmflow rate.

- The PCS liquid filmflow is credited only following a 337-second delay. This corresponds to the time needed to establish a steady liquid film coverage pattern based on the AP600 initial flow rate of 1666 Liters/min (about 440 gpm). The higher initial flow rate for the AP1000, 1775.7 Liters/min (about 469.1 gpm), helps to offset the increased height of the AP1000 containment wall and would result in a shorter delay time. However, Westinghouse has maintained the 337-second delay for the AP1000 licensing analyses, as described in Section 7 of WCAP-15846, Revision 1.

- The water coverage is obtained from the limiting flow model, as described in Section 7 of WCAP-15846, Revision 1, based on the wetted surface areas listed in Table 6.2-3 of this report. 2-D conduction can be considered in the limiting flow model to account for heat conduction from the dry to wet regions of the containment shell when the PCS water coverage is reduced if the water level in the PCCWST falls below 6.19 m (20.3 ft).

- A 0.051-cm (20-mil) air gap is assumed between the steel liner and the concrete on applicable internal heat sinks.

- The loss coefficient in the external annulus includes a 30-percent increase over the value derived from the test program.

- Condensation and convection on heat sinks in the dead-ended compartments, below the operating deck, are not credited after the blowdown period (about 30 seconds after accident initiation). This conservative assumption is also employed for MSLB analyses.
- Heat transfer to horizontal, upward-facing surfaces that may become covered with a condensation film is not credited.

Table 6.2-4 of this report summarizes the limiting LOCA and MSLB peak containment pressure and temperature calculations provided in support of the design certification.

The staff has allowed Westinghouse to move the heat sink information from DCD Tier 2 (previously provided in Table 6.2.1.1-4, "Metal Heat Sinks"; Table 6.2.1.1-5, "Concrete Heat Sinks"; Table 6.2.1.1-6, "Containment Shell and Baffle Heat Sinks"; and Table 6.2.1.1-7, "Shield Building Concrete Heat Sinks") by reference to Section 13 of WCAP-15846, Revision 1, which is considered to be fully proprietary to Westinghouse Electric Company.

Summary of Staff CONTAIN Analyses

The staff performed independent confirmatory analysis with the CONTAIN 2.0 computer code for the limiting LOCA and limiting MSLB cases (Memorandum from J. Rosenthal, RES, to J. Hannon, NRR, "AP1000 Containment DBA Calculations Using the CONTAIN Code," dated March 26, 2003). These analyses indicate similar characteristics for the PCS performance in both the limiting LOCA and limiting MSLB events. The calculated peak pressure for the MSLB was about 3.4 kPa (0.5 psi) higher than the WGOTHIC value. For the LOCA case, the calculated peak pressure was about 2.76 kPa (0.4 psi) lower than the WGOTHIC value. The acceptability of the PCS is based on the results of the WGOTHIC analyses.

Long-Term Internal Pressure Analysis

The objective of the long-term internal pressure analysis is to demonstrate that the design is consistent with the design requirements of GDC 38, which provide for containment temperature and pressure to be maintained at acceptably low levels following any LOCA.

In Item II.b of Section 6.2.1.1.A of the SRP, the staff guidance used to evaluate compliance with GDC 38, is that the containment pressure should be reduced to less than 50 percent of its peak value within 24 hours of the occurrence of a design-basis LOCA. This assures that the containment leak rate used for the siting evaluation is consistent with the design basis analysis assumption. Westinghouse proposed that the calculated pressure reduction be based on 50 percent of the design pressure to be consistent with current guidelines related to GDC 38. The staff found this approach acceptable since the peak calculated pressures are near the design value.

Westinghouse presented the results of an analysis for the long-term containment pressure resulting from the design-basis LOCA, including the 2-D correction, to demonstrate the desired result, that the long-term (post 24-hour) pressure remains below 50 percent of the design pressure. (See DCD Tier 2, Figure 6.2.1.1-7.) This analysis is for the cold-leg break LOCA.

This LOCA case also results in the most limiting peak containment pressure of 499.84 kPa (57.8 psig) at approximately 1,800 seconds into the event.

DCD Tier 2, Figure 6.2.1.1-9, provides the response for the limiting hot-leg break LOCA. For the MSLB, the pipe break spectrum analysis has identified the full double-ended rupture at 30 percent power as the limiting break with respect to peak containment pressure. DCD Tier 2, Figure 6.2.1.1-1 illustrates this response. This limiting MSLB case yields a peak containment pressure of 496.39 kPa (57.3 psig) at approximately 810 seconds into the event. The containment pressure rises until the secondary side blowdown is complete. Once blowdown is completed, there is no additional mass or energy released to containment. With no mass and energy source, the containment pressure rapidly decreases as the internal heat sinks and PCS continue to absorb energy. The 2-D heat conduction enhancement to the evaporation limited flow model is not applicable to the MSLB because the accident is terminated following blowdown prior to the time the enhancement would be applied, after the first PCCWST standpipe uncovers.

DCD Tier 2, Table 6.2.1.1-3 provides the calculated pressure for the most limiting DBA. This table demonstrates that the long-term containment pressure following the limiting LOCA is maintained at an acceptably low level as required by GDC 38.

The staff considers the AP1000 PCS design to be in compliance with GDC 38. The system safety function to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any LOCA and maintain them at acceptably low levels has been demonstrated. The staff believes that there is a real effect from 2-D heat conduction. However, as an insufficient amount of test data is available to validate this model, the staff is unable to determine how much credit should be given in evaluating the Westinghouse design performance after 24 hours. A separate analysis was performed for the limiting LOCA without 2-D conduction, as discussed in DCD Tier 2, Section 6.2.1.1.3, "Design Evaluation." This separate analysis confirmed the assumption used in DCD Tier 2, Section 15.6.5.3.3 of reducing the containment leakage to half its design value after 24 hours. Although the containment pressure response is different from current licensed plants, the PCS is acceptable and consistent with the passive design objectives on which the AP1000 PCS is based.

External Pressure Analysis

The staff reviewed the analysis conducted to determine the maximum external pressure, or reverse differential pressure, that would result from design-basis events or inadvertent system actuations. Conformance with the criteria of SRP Section 6.2.1.1.A, "Containment Functional Design—PWR Dry Containments, Including Subatmospheric Containments," forms the basis for concluding whether the Westinghouse maximum external pressure analysis satisfies the following requirement:

- GDC 16, as it relates to the reactor containment and associated systems being provided to assure that containment design conditions important to safety are not exceeded for as long as postulated accident conditions require

The worst case scenario presented by Westinghouse for the maximum external pressure was the loss of all ac power sources during extreme cold weather. The pressure evaluation was conducted using the WGOTHIC code, and assumed that all ac power sources were lost, resulting in a reduction of heat generated in containment. An ambient temperature of -40 °C (-40 °F) and a steady 21.5 m/sec (48 mph) wind outside of containment were also assumed, thereby maximizing the cooling of the containment atmosphere and maximizing the differential pressure across the containment vessel. Other analytical assumptions were as follows:

- An initial internal containment temperature of 49 °C (120 °F) was assumed, to maximize the heat transfer from the containment wall and maximize the pressure differential across the containment vessel.
- An initial internal relative humidity of 100 percent was assumed, to minimize the air in containment, allowing for a greater reduction in pressure from the condensation of steam.
- An initial containment pressure of 99.97 kPa (or -0.2 psig) was assumed, consistent with the TS limiting condition for operation (LCO).
- No air leakage into the containment was assumed during the transient.

The calculated differential pressure across the containment vessel is approximately 16.6 kPa (2.4 psid). The design external pressure is 20 kPa (2.9 psid). To mitigate the event, Westinghouse states in DCD Tier 2, Section 6.2.1.1.4, that containment pressure instruments (four total) would indicate the containment pressure, and operators could open the containment ventilation purge isolation valves, which are powered by Class 1E batteries, to restore containment pressure. Westinghouse further states in the DCD that operators would have sufficient time to restore the pressure before reaching the design external pressure limit.

The staff notes that because the AP1000 has no safety-related ac power, the loss of all ac power is not a beyond-design-basis event, as it would be for a plant with safety-related ac. Events involving inadvertent PCS actuation, failed fan cooler controls, malfunction of containment purge valves, drainage of the IRWST into containment, prolonged operation of the ejector in the primary sample system, and the maximum ambient temperature change were considered, but Westinghouse found them nonbounding.

In plants with active containment engineered safety heat removal systems, such as sprays, the inadvertent actuation of these systems would cool the containment, reduce the pressure, and result in the bounding event. The inadvertent actuation of the PCS with the containment fan coolers in operation is not considered to be a bounding event. The chilled water supply and return lines to the containment recirculation cooling system fan coolers isolate following any event resulting in a containment isolation signal to provide containment integrity. Operation of the containment fan coolers is limited by the minimum temperature, 4.4 °C (40 °F), of the chilled water system. The maximum heat transfer from containment for the external pressure transient was chosen without PCS operation because the heated water within the PCS water storage tank (minimum temperature of 4.4 °C (40 °F)) would tend to heat the containment shell, particularly at the elevated flow rates for the first few hours when compared to the extreme cold temperature, -40 °C (-40 °F). The staff finds that Westinghouse has identified the most limiting case with regard to the maximum reverse differential pressure.

In an SRM dated June 30, 1997, the Commission approved the staff's recommendation that the AP600 include a containment spray system, or equivalent, for accident management following a severe accident. The AP1000 design also includes a containment spray system for accident management following a severe accident. DCD Tier 2, Section 6.5.2, describes the containment spray system, and Section 19.2.3.3.9 of this report includes the staff's evaluation of the system.

As noted in DCD Tier 2, Section 6.5.2.1.4, the use of the containment spray during power operation requires multiple failures of closed valves, including a locked closed valve outside of containment, and a remotely operated valve inside containment, from the MCR or remote access workstation. Therefore, the staff finds inadvertent actuation of the containment spray system during power operations not credible. Inadvertent spray actuation does not need to be considered for the external pressure evaluation.

During shutdown modes, the containment isolation valves are open and the header for the fire protection water inside containment is pressurized. When the header inside containment is pressurized, an additional manual valve between the header and the remotely operated valve on the line to the spray ring is closed. During shutdown modes, the pressure in the fire protection header is caused by the head of water in the PCS storage tank on the roof of the shield building. Pressurization of the spray ring by the water storage tank would result in flow through the nozzles, but insufficient flow to produce a spray. To produce spray from the spray ring, a fire pump must be operating and the appropriate valves open to the containment fire protection header. The connection from the fire pumps to the containment header is normally closed with a manual valve located outside containment. Therefore, the staff finds inadvertent actuation of the containment spray system during shutdown operations not credible, and inadvertent spray actuation does not need to be considered for the external pressure evaluation.

On the basis of its review, the staff finds that Westinghouse has identified the bounding event (loss of all ac power sources during extreme cold weather) for the maximum external containment pressure. Westinghouse has satisfied GDC 16 by providing acceptable margin between the maximum calculated reverse differential pressure and the design differential pressure, and has stated that operators would be able to restore containment pressure before the reverse differential pressure design limit is reached. This provides assurance that containment design conditions important to safety are not exceeded for the duration of accident conditions. The staff, therefore, finds the Westinghouse maximum external pressure analysis acceptable.

6.2.1.2 <u>Subcompartment Analysis</u>

The staff reviewed the analysis conducted to determine the maximum differential pressure, or loading, that the containment subcompartment walls would be subjected to as a result of the most limiting postulated line break within a particular subcompartment. Conformance with the criteria of SRP Section 6.2.1.2, "Subcompartment Analysis," and SRP Section 6.2.1.3, "Mass and Energy Release Analysis For Postulated Loss-of-Coolant Accidents," forms the basis for concluding whether the Westinghouse subcompartment analysis satisfies the following requirements:

- GDC 4, regarding the appropriate protection of SSCs important to safety against dynamic effects that may result from equipment failures

- GDC 50, regarding the ability of the reactor containment structure and its internal compartments to accommodate the calculated pressure and temperature conditions resulting from any LOCA

Selection of Postulated Breaks and Subcompartments

As discussed in DCD Tier 2, Section 6.2.1.2, Westinghouse applied the leak-before-break (LBB) concept to the RCS high-energy piping. LBB is applicable to RCS piping 15.24 cm (6 in) in diameter or greater. The general concept of LBB is that piping for which LBB has been demonstrated to be applicable, by deterministic and experimental methods, would leak at a detectable rate from postulated flaws before catastrophic failure of the pipe would occur as a result of loads experienced under normal, anticipated transient, and safe-shutdown earthquake (SSE) conditions. Application of LBB to the containment subcompartment analysis allows the postulated rupture of large pipes to be precluded from the spectrum of postulated breaks. DCD Tier 2, Section 3.6, "Protection Against the Dynamic Effects Associated with the Postulated Rupture of Piping," summarizes the LBB evaluation.

GDC 4 states, in part, that "dynamic effects associated with postulated pipe ruptures...may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping." Therefore, for the LBB concept to be acceptable with respect to subcompartment analysis, the applicant must demonstrate that the probability of a particular rupture is extremely low under design-basis conditions. Section 3.6.3 of this report discusses the staff's evaluation and acceptance of LBB for the AP1000.

Table 6.2-5 of this report summarizes the postulated breaks and design pressures for the subcompartments analyzed. For all subcompartments, the postulated breaks envelop other line breaks that could be postulated to rupture (in accordance with the size limits of LBB) in the particular area.

Table 6.2-5 Postulated Breaks and Subcompartment Design Pressures

Subcompartment	Postulated Break	Design Pressure
Steam generator compartment and access area	10.16-cm (4-in.) pressurizer spray line 10.16-cm (4-in.) SG blowdown line 7.62-cm (3-in.) RCS cold-leg pipe 7.62-cm (3-in.) RCS hot-leg pipe	34.5 kPa (5 psid)

Subcompartment	Postulated Break	Design Pressure
Pressurizer valve room	10.16-cm (4-in.) pressurizer spray line	34.5 kPa (5 psid)
CVS room	7.62-cm (3-in.) RCS cold-leg pipe	34.5 kPa (5 psid)
CVS pipe tunnel	10.16-cm (4-in.) SG blowdown line	51.7 kPa (7.5 psid)
Maintenance floor and operating compartment walls	0.093-m^2 (1-ft^2) main steamline rupture	34.5 kPa (5 psid)

Westinghouse performed an evaluation of rooms which could have either a main or startup feedwater line break. No significant pressurization of the rooms is expected to occur because the postulated breaks are located in regions which are open to the large free volume of the containment. For these regions, the main or startup feedwater line breaks are not limiting.

The reactor vessel cavity was analyzed for asymmetric pressurization resulting from a 18.9 Liters/min (5-gpm) leak rate crack in the primary piping. The reactor vessel cavity was not analyzed for asymmetric loading from pipe breaks because all of the piping in the reactor vessel cavity is qualified to LBB, which also applies to the weld joining the RCS piping in the vessel cavity and the "safe-ends," or nozzles, attached to the reactor vessel. The staff's acceptance of LBB in Section 3.6.3 of this report encompasses pipe welds and breaks at weld locations that do not need to be postulated for LBB piping for the purpose of the subcompartment pressurization analysis.

The pressurization loads for the IRWST are determined by the pressure and hydrodynamic loads from the discharge of the first, second, and third stage of the automatic depressurization system (ADS), as discussed in DCD Tier 2, Section 3.6.1, "Postulated Piping Failures in Fluid Systems Inside and Outside Containment." Westinghouse conducted an analysis to determine the hydrodynamic loading on the IRWST due to ADS discharge. Section 6.2.8 of this report discusses the staff's review and acceptability of this analysis.

<u>Differential Pressure Analysis</u>

To obtain the fluid mass and energy released from the postulated breaks, Westinghouse used the modified Zaloudek correlation to calculate the critical mass flux for the 7.62-cm (3-in.) cold-leg break, the 7.62-cm (3-in) hot-leg break, and the 10.16-cm (4-in.) SG blowdown line break. For the 10.16-cm (4-in.) pressurizer spray line break, the Fauske breakflow model in NOTRUMP was used. The modified Zaloudek correlation used for pipes other than the *pressurizer spray line helps create a smooth transition between subcooled and saturated flow* regimes when the pressure in the break element exceeds the saturation pressure. With the modified Zaloudek correlation, Westinghouse assumed the mass flux to remain constant at initial full-power conditions to maximize the mass and energy release, resulting in a *conservatively large release to the containment.*

NOTRUMP is used for certain breaks. NOTRUMP better models the more complex depressurization that occurs with the vapor and subcooled liquid that is released through both sides of the pressurizer spray line break. The NOTRUMP piping model does not include friction losses, which result in a higher pressure at the break and thus a greater mass release, which is conservative. Because NOTRUMP conservatively models the AP1000 depressurization, the staff finds this acceptable.

Westinghouse chose the initial conditions of the subcompartment atmosphere to maximize the calculated differential pressures. These include use of the maximum allowable air temperature, minimum pressure, and minimum relative humidity.

Westinghouse used the TMD computer code, described in WCAP-8077, "Ice Condenser Containment Pressure Transient Analysis Methods"; WCAP-8077, March 1973 (proprietary); and WCAP-8078 (nonproprietary) to calculate the differential pressure across the subcompartment walls. It assumed 100-percent entrainment of fluid droplets because this yielded the largest differential pressure. Westinghouse used the unaugmented critical flow model option in TMD to predict the critical mass flow rate between nodes. Furthermore, no credit was taken for vent paths which become available only after the break occurs, such as blowout panels, doors, and collapsing insulation.

The staff finds that the TMD modeling assumptions meet the guidance in SRP Section 6.2.1.2. In particular, this guidance provides for the following:

- The nodalization should be chosen so that substantial pressure gradients do not exist within a node, and 100-percent entrainment should be assumed.
- Vent flow should be based on homogeneous mixture in thermal equilibrium with 100-percent water entrainment.
- The maximum allowable air temperature, minimum pressure, and minimum relative humidity should be assumed for initial conditions.

Some of the subcompartments may not meet the 40-percent pressure margin specified in SRP Section 6.2.1.2, for the CP stage of a review. However, the calculations show margins still exist. At the OL stage of a review, the SRP guidance is that the peak differential pressure should not exceed the design pressure. The staff has determined that the few exceptions to the 40-percent margin are acceptable for design certification.

The staff reviewed the short-term mass and energy release data, and the methodology as it applies to the AP1000. The staff finds that Westinghouse meets the guidance provided in SRP Section 6.2.1.3 regarding the mass and energy release used in the analysis by assuming a constant mass blowdown rate and using an acceptable choked flow correlation. With regard to the choked flow model, the staff has previously found use of the modified Zaloudek coefficient acceptable through its approval of WCAP-8264, "Westinghouse Mass and Energy Release Data for Containment Design"; WCAP-8264-P-A, June 1975 (proprietary); and WCAP-8312-A, Revision 2, August 1975 (nonproprietary). Furthermore, SATAN-VI has been found acceptable through the staff's review of WCAP-10325, "Westinghouse LOCA Mass and Energy Release

Model for Containment Design—March 1979 Version" and WCAP-10325, May 1983 (proprietary). NOTRUMP has been found acceptable for use in currently licensed plants for small line breaks, as discussed in Chapter 21 of this report.

Although the staff approved the TMD and SATAN-VI codes used for subcompartment analysis for previously licensed plants, it reviewed the use of these codes as they apply to the AP1000, as well as the modeling assumptions made by Westinghouse.

In SRP Section 6.2.1.1.B, "Ice Condenser Containments," the staff found the TMD code acceptable for subcompartment analyses, provided that the unaugmented critical flow model was used. While the AP1000 is not an ice condenser containment, the staff has previously found TMD acceptable for non-ice condenser operating plants.

The staff finds the correlations, computer codes, and methodologies used by Westinghouse acceptable for the AP1000 subcompartment pressurization analysis.

In conclusion, the staff finds that Westinghouse has satisfied GDC 4 with regard to containment subcompartments by considering the dynamic effects of postulated pipe ruptures within subcompartments. Consistent with GDC 4, Westinghouse has shown, by analysis, that pipe breaks above a certain size can be precluded from that piping for which breaks must be postulated. Furthermore, Westinghouse has satisfied GDC 50 by designing containment subcompartment walls to withstand, with appropriate margin, the calculated differential pressures resulting from pipe breaks postulated in accordance GDC 4. Therefore, the staff finds the Westinghouse containment subcompartment pressurization analysis acceptable.

6.2.1.3 Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents

Westinghouse documented mass and energy releases for two different types of transients, the subcompartment differential pressure analysis and the containment integrity analysis. The first analysis (mass and energy release analyses in support of the subcompartment differential pressure analysis) was referred to as a short-term analysis because it focused on blowdown. The staff evaluated these releases and found them acceptable with the criteria of SRP Section 6.2.2, "Subcompartment Analysis," and SRP Section 6.2.1.3, "Mass and Energy Release Analysis For Postulated Loss of Coolant Accidents" (see Section 6.2.1.2 of this report).

The second type of analysis described the methodology used to determine the releases for the containment pressure and temperature calculations using the WGOTHIC code (referred to as the long-term analysis). These releases were used for the containment integrity analysis discussed in Section 6.2.1.1 of this report.

The long-term analysis considered the limiting break size for containment integrity analysis and the LOCA design basis as the complete, double-ended guillotine severance of the largest RCS pipe. The release rates were calculated for pipe failure at two locations (the hot-leg and the cold-leg). These break locations were analyzed for both the short-term and the long-term transients. Because the initial operating pressure of the RCS is approximately 15,513 kPa (2,250 psi), the mass and energy would be released extremely rapidly when a break occurs. As the water exits from the broken pipe, a portion of it would flash to steam because of the differences in pressure and temperature between the RCS and containment. The RCS would depressurize rapidly because breakflow would exit on both sides of the pipe.

Long-Term Mass and Energy Release Data

A long-term LOCA analysis calculational model is typically divided into the following four phases:

(1) blowdown, which includes the period from the accident initiation (when the reactor is in a steady-state, full-power operation condition) to the time that the broken loop pressure equalizes to the containment pressure

(2) refill, which is the time from the end of the blowdown to the time when the ECCS refills the vessel lower plenum

(3) reflood, which begins when the water starts to flood the core and continues until the core is completely quenched

(4) post-reflood, which is the period after the core has been quenched and energy is released to the RCS primary system by the RCS metal, core decay heat, and the SGs

The Westinghouse long-term analysis considered only the blowdown, reflood, and post-reflood phases of the transient. The refill period is omitted from the analyses because Westinghouse assumed that the refill period occurred immediately upon the end of blowdown, so that the releases to the containment were maximized. This assumption is consistent with the guidance provided in SRP 6.2.1.3, Section II.3.c.

The AP1000 long-term LOCA mass and energy releases were predicted for the blowdown phase for postulated double-ended cold-leg and double-ended hot-leg breaks. The blowdown phase mass and energy releases were calculated using the SATAN-VI computer code (see WCAP-10325-P-A (proprietary) and WCAP-1032S-A (nonproprietary), May 1983).

The staff reviewed the long-term LOCA mass and energy release data, and the methodology as it applies to the AP1000. This methodology is described in Section 14, "LOCA Mass and Energy Release Calculation Methodology," of WCAP-15846, Revision 1. The staff has determined that the SATAN-VI LOCA blowdown computer program is acceptable for use in obtaining LOCA mass and energy releases for the LOCA blowdown phase for containment analyses. SATAN-VI has been approved by the staff for this purpose, as discussed in SRP Section 6.2.1.4, and models the AP1000 passive safety features in a conservative manner. The postblowdown mass and energy releases back into the containment atmosphere from the accumulators, CMTs, and IRWST injection into the RCS were found to be acceptable. The increased mass and energy released from the primary system is consistent with the guidance in SRP Sections 6.2.1.4 and 6.2.1.1.A to maximize the calculated containment pressure and temperature. In the AP1000, for LOCA analyses, the break location switches to the fourth-stage ADS at about 1500 seconds into the limiting LOCA scenario.

Energy Sources

The following energy sources were accounted for by Westinghouse in the long-term LOCA mass and energy calculation:

- decay heat
- core stored energy
- RCS fluid and metal energy
- SG fluid and metal energy
- accumulators
- CMTs
- IRWST
- zirconium-water reaction

Westinghouse employed the following assumptions to analyze the core energy release for maximum containment pressure:

- maximum expected operating temperature
- allowance in initial temperature to account for instrument error and deadband
- margin in RCS volume (+1.4 percent)
- allowance in volume for thermal expansion (+1.6 percent)
- 100-percent, full-power operation
- allowance for calorimetric error (+1.0 percent of full power)
- conservatively modified coefficients of heat transfer, which ensure that RCS metal and SG stored energies are released at a conservatively high rate
- allowance in core stored energy for fuel densification effect
- margin in core stored energy (+15.0 percent)
- allowance in initial pressure to account for instrument error and deadband
- margin in SG mass inventory (+10.0 percent)
- 1 percent of the zirconium around the fuel reacts

The staff reviewed the methods and assumptions used to release the various energy sources during the blowdown phase. The staff found the methods and assumptions increase the stored energy in the primary system consistent with the guidance in SRP Sections 6.2.1.4 and 6.2.1.1.A to maximize the calculated containment pressure and temperature. Therefore, the methods and assumptions are acceptable for the licensing analyses.

Engineered Safety Features

Description of Blowdown Model

Westinghouse employed the SATAN-VI model to determine the mass and energy released from the RCS during the blowdown phase of a postulated LOCA. The model is described in WCAP-10325, dated May 1983.

Description of Postblowdown Model

Westinghouse used the mass and energy inventories at the end of blowdown to define the initial conditions for the beginning of the reflood portion of the transient. The broken and unbroken loop SG inventories were kept separate to account for potential differences in the cooldown rate between the loops. In addition, the mass added to the RCS from the IRWST was returned to containment as breakflow so that no net change in system mass occurred.

Energy addition from decay heat was computed using the 1979 American Nuclear Society (ANS) standard (plus 2 sigma) decay heat table. The energy release rates from the RCS metal and SG metal were modeled using exponential decay rates, which generally exhibit an initial rapid energy release followed by a significantly slower, gradual release of energy.

The accumulator, CMT, and IRWST mass flow rates are computed from the end of blowdown to the time the tanks empty. The rate of RCS mass accumulation is assumed to decrease exponentially during the reflood phase. More CMT and accumulator flow is spilled from the break as the system refills. The breakflow rate is determined by subtracting the RCS mass addition rate from the sum of the accumulator, CMT, and IRWST flow rates.

The primary differences between the AP1000 design and currently operating Westinghouse PWRs are the ESFs. The safety features of currently operating plants include passive and active systems, while the AP1000 safety features are only passive. However, this difference only affects long-term inventory makeup systems and not the system behavior during the blowdown phase. The only safety feature which participates during blowdown is the accumulator system, which is included in both current plants and the AP1000 and is modeled with the NRC-approved LOCA mass and energy release methodology. The AP1000 uses spherical accumulators, whereas currently operating Westinghouse-designed plants use cylindrical accumulators. The accumulator inventory is depleted well before the time of peak pressure, so any difference in discharge rate associated with the different accumulator geometry would have an insignificant effect on the calculation for peak containment pressure. The gravity-driven CMTs do not operate in the blowdown timeframe and are not included in the SATAN-VI model. CMTs cannot inject into the common direct vessel injection (DVI) line against the pressure of the gas-charged accumulators during the blowdown phase of the accident. Therefore, the methodology for calculating the mass and energy release to containment during the blowdown is not affected by the AP1000 passive systems.

The variable noding structure of the SATAN model allows the user to simulate current and advanced RCS geometries with generalized control volumes. The standard Westinghouse PWR RCS noding was modified to specifically model the AP1000 RCS geometry. This modeling included two cold-legs in the broken loop and the DVI line to the downcomer.

No changes in the approved, conservative design-basis methodology or modeling assumptions, as described in WCAP-10325-P-A, have been made to the SATAN-VI code to model the AP1000. The behavior of the release of the initial RCS inventory during the initial blowdown for the AP1000 is identical to currently operating plants. The flexibility of the noding structure in a SATAN-VI model allows for an accurate representation of the AP1000 geometry.

Therefore, the SATAN-VI code is acceptable for predicting the mass and energy releases during the blowdown phase for the AP1000 design.

Mass that is added to and remains in the vessel is assumed to be raised to saturation. Therefore, the actual amount of energy available for release to the containment for a given time period is determined from the difference between the energy required to raise the temperature of the incoming flow to saturation and the sum of the decay heat, core stored energy, RCS metal energy, and SG mass and metal energy release rates. The energy release rate for the available breakflow is determined from a comparison of the total energy available release rate and the energy release rate, assuming that the breakflow was 100 percent saturated steam. Saturated steam releases maximize the calculated containment pressurization.

The staff reviewed the postblowdown model as it applies to the AP1000. The staff found the postblowdown model increases the mass and energy released from the primary system consistent with the guidance in SRP Sections 6.2.1.4 and 6.2.1.1.A. Therefore, the model is acceptable for the licensing analyses because it maximizes the calculated containment pressure and temperature.

Single-Failure Analysis

The assumptions for the containment mass and energy release analysis are intended to maximize the calculated release. For the LOCA mass and energy releases, a single failure could reduce the flow rate of water to the RCS, but would not disable the passive core cooling function. For example, if one of the two parallel valves from the CMT were to fail to open, the injection flow rate would be reduced and, as a result, the break mass release rate would decrease. Therefore, to maximize the releases, the AP1000 mass and energy release calculations conservatively do not assume a single failure. The effects of a single failure in the PCS are taken into account in the containment analysis.

Containment Response Analysis and Initial Conditions

Westinghouse employed the WGOTHIC computer code to determine the containment response following a LOCA. Section 6.2.1.1 of this report discusses the staff's review of the initial conditions for LOCA analyses, the WGOTHIC code, and its results.

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary System Pipe Rupture Inside Containment

A steamline rupture occurring in containment releases significant amounts of high-energy steam to the containment environment, resulting in high containment temperatures and pressures which may challenge design limits. Various break sizes and power levels are analyzed to determine the limiting break case for containment integrity. Steamline breaks are postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Because SG mass decreases with increasing power level, breaks occurring at a lower power generally result in a greater total mass release to the containment. Because of increased energy storage in the primary system, increased heat transfer in the SGs, and additional energy generation in the nuclear fuel, the energy released to the containment from breaks postulated to occur during power operation may be greater than for breaks occurring with the plant in a hot-shutdown condition. Additionally, steam pressure and the dynamic conditions in the SGs change with increasing power. This has significant influence on both the rate of blowdown and the amount of moisture entrained in the fluid leaving the break following an event.

Break area is also important when evaluating steamline breaks. It controls the rate of releases to the containment, and influences the steam pressure decay and the amount of entrained water in the blowdown flow. The MSLB analysis used to determine the limiting break case for peak containment pressure was found to be a full, double-ended pipe rupture downstream of the steamline flow restrictor. For this case, the actual break area equals the cross-sectional area of the steamline, but the blowdown from the SG with the broken line is controlled by the flow restrictor throat area (0.13 m^2 (1.4 ft^2) nominal). The reverse flow from the intact SG is controlled by the smaller of the pipe cross-section, the steam stop valve seat area, or the total flow restrictor throat area in the intact SG. The reverse flow has been conservatively assumed to be controlled by the flow restrictor in the intact loop SG.

Because of the opposing effects of changing power level on steamline break releases, no single power level can be identified as a worst case initial condition for a steamline break event. Therefore, several different power levels spanning the operating range, as well as the hot shutdown condition were analyzed, including 101-percent, 70-percent, 30-percent, and 0-percent power.

The effects of the assumption of the availability of offsite power are enveloped in the analysis. Offsite power is assumed to be available where it maximizes the mass and energy released from the break because of the following:

- The continued operation of the RCPs, until automatically tripped as a result of CMT actuation, maximizes the energy transferred from the RCS to the SG.
- The continued operation of the feedwater pumps and actuation of the startup feedwater system, until they are automatically terminated, maximizes the SG inventories available for release.

The AP1000 is equipped with a passive safeguards system, including the CMT and the PRHR HX. Following a steamline rupture, these passive systems are actuated when their setpoints are reached. This decreases the primary coolant temperatures. The actuation and operation of these passive safeguards systems do not require the availability of offsite power.

When the PRHR is in operation, the core-generated heat is dissipated to the IRWST by means of the PRHR HX. This causes a reduction of the heat transfer from the primary system to the

SG secondary system, resulting in a reduction of mass and energy releases because of the break.

The availability of ac power, in conjunction with the passive safeguards system (CMT and PRHR), maximizes the mass and energy releases resulting from the break. Therefore, blowdown occurring in conjunction with the availability of offsite power is more severe than for cases in which offsite power is not available.

Analyses that considered single active failure of either one main steamline isolation valve (MSIV) or one feedwater isolation valve determined that the main feedwater isolation valve failure was not limiting. The spectrum of cases analyzed to determine the limiting MSLB event all assume the failure of one MSIV.

The containment response to the MSLB event is determined by the magnitude and duration of the mass and energy releases, the containment volume, steam/air circulation to the heat sinks, and time response of the heat sinks. Because of the nature of the secondary-side releases discussed in the previous section, the MSLB transient is characterized by the addition of superheated steam to the containment throughout the transient. Consistent with the guidance established in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," a value of 8-percent revaporization is assumed for all MSLB transients analyzed.

The containment pressure continues to rise until the secondary-side blowdown is complete. Once blowdown is complete, no additional mass or energy is released to the containment. With no mass and energy source, the containment pressure decreases rapidly as the internal heat sinks and PCS continue to absorb energy.

The pipe break spectrum analysis has identified the full double-ended rupture at 30-percent power as the limiting break with respect to peak containment pressure. This limiting MSLB case yields a peak containment pressure of 496.39 kPa (57.3 psig) at about 810 seconds into the event.

<u>Significant Parameters Affecting Steamline Break Mass and Energy Releases</u>

The following four major factors influence the release of mass and energy following a steamline break:

(1) SG fluid inventory
(2) primary-to-secondary heat transfer
(3) protective system operation
(4) the state of the secondary fluid blowdown

The following is a list of plant variables that have a significant influence on the mass and energy releases:

- plant power level
- main feedwater system design

Engineered Safety Features

- startup feedwater system design
- postulated break type, size, and location
- availability of offsite power
- safety system failures
- SG reverse heat transfer and RCS metal heat capacity

The staff reviewed the significant parameters affecting steamline break mass and energy releases as they apply to the AP1000 and found them acceptable because they maximize the calculated peak containment pressure, consistent with the guidance in SRP Section 6.2.1.1.A.

Description of Blowdown Model and Mass and Energy Release Data

In the AP1000 analysis, Westinghouse employed the blowdown models described in WCAP-8822, "Mass and Energy Releases Following a Steamline Rupture," by R.E. Land, dated September 1976. The LOFTRAN-AP computer program is used to determine the mass and energy releases from steamline breaks ("LOFTRAN and LOFTTR2 AP1000 Code Applicability Document," WCAP-14234, Revision 1 (proprietary), June 1997).

The above-cited methodologies reflect current technology by including the effect of SG superheat. The staff reviewed the application of these methodologies to the AP1000 and found them to be acceptable because they are consistent with the guidance provided in the SRP Section 6.2.1.4, "Mass and Energy Release Analysis for Postulated Secondary System Pipe Rupture," Section II, to produce a conservative result.

Containment Response Analysis and Initial Conditions

Westinghouse employed the WGOTHIC computer code to determine the containment response following a steamline break. Section 6.2.1.1 of this report discusses the staff's review of the initial conditions for steamline break analysis, the WGOTHIC code, and its results.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of the ECCS

The staff reviewed the analysis conducted to determine the minimum containment pressure that could exist during the period of time until the core is reflooded following a LOCA. It conducted this review to confirm the validity of the pressure used as a boundary condition in the ECCS performance studies. Conformance with the criteria of SRP Section 6.2.1.5, "Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Capability Studies," forms the basis for concluding whether the Westinghouse minimum containment pressure analysis satisfies the following requirements:

- Section I.D.2 of Appendix K to 10 CFR Part 50, which requires that the containment pressure used in ECCS reflood calculations not exceed a pressure calculated conservatively for that purpose

- 10 CFR 50.46, which requires that ECCS cooling performance be calculated in accordance with an acceptable evaluation model

DCD Tier 2, Section 6.2.1.5, discusses the containment analysis used to determine the minimum backpressure for input as a boundary condition in the ECCS evaluation model. Generally, the core flooding rate of a PWR is dependent on the ability of the ECCS to displace steam generated in the reactor vessel; there is a direct correlation between the containment pressure and the rate of core reflood. Minimizing the containment pressure used as a boundary condition in the ECCS analysis is therefore considered conservative. Any pressurization of the containment above 101 kPa (14.7 psia) will enhance the calculated ECCS performance of the AP1000 limiting case, large-break LOCA presented in DCD Tier 2, Section 15.6.5.

DCD Tier 2, Figure 6.2.1.5-1, graphically depicts the calculated containment backpressure used by Westinghouse for the AP1000 ECCS analysis. The peak minimized containment pressure is approximately 262.69 kPa (23.4 psig), as compared to the peak pressure of approximately 508.12 kPa (59 psig) calculated for containment design and leakage considerations.

As discussed in DCD Tier 2, Section 6.2.1.5, a single-node WGOTHIC model was used to calculate the minimum containment pressure. Conditions used to minimize the calculated containment pressure were as follows:

- initial pressure of 101 kPa (14.7 psia)
- initial temperature of 32 °C (90 °F)
- initial relative humidity of 99 percent
- assumed temperature of −18 °C (0 °F) in the shield building annulus
- addition of 10 percent to the containment volume
- increase of passive heat sink surface areas by a factor of 2.1
- during the blowdown period inside containment, use of the Tagami heat transfer correlation with a multiplier of 4
- for the postblowdown period inside containment, use of the Uchida heat transfer correlation with a multiplier of 1.2
- containment purge was assumed to be in operation through two, 38.1-cm- (15-in.-) diameter lines (40.6-cm- (16-in.-) schedule 40 pipe) until the lines are isolated at 22 seconds following the beginning of the LOCA, at a 156.5-kPa (8-psig) closure setpoint

These assumptions are consistent with those outlined in BTP Containment Systems Branch (CSB) B 6-1, "Minimum Containment Pressure Model For PWR ECCS Performance Evaluation" of SRP Section 6.2.1.5. The mass and energy releases used in the minimum containment pressure analysis were determined consistent with Appendix K to 10 CFR Part 50, and are described in WCAP-14171 (WCOBRA/TRAC). These mass and energy releases are consistent with SRP Section 6.2.1.5, which specifies that the releases should be based on Appendix K of 10 CFR Part 50.

BTP CSB 6-1 also states that the mixing of subcooled ECCS water from the break with the steam atmosphere should be assumed to minimize the pressure. In the Westinghouse analyses, the mass and energy released from the break during blowdown is assumed to mix with the containment atmosphere. Spillage of ECCS water into the containment is not modeled because all ECCS injection is directly into the vessel and no line exists from which it could spill.

In addition, BTP CSB 6-1 specifies that pressure-reducing equipment, such as containment sprays and containment fan coolers, should be assumed to be running to minimize the containment pressure. The Westinghouse minimum backpressure analysis does not assume the containment recirculation cooling system to be operating. At about 6 seconds following the initiation of the accident, the containment recirculation cooling system would be secured on a containment isolation signal, and the impact of operation of the cooling system for 6 seconds would be small. Because the breakflow is dominated by critical flow during the period when the peak clad temperature occurs, a lower containment pressure would have no effect on the RCS or cladding temperature. Therefore, the staff finds the licensing analyses without the containment recirculation cooling system to be acceptable for the AP1000 minimum containment pressure evaluation.

PCS flow is not modeled because the time period of interest in the analysis is approximately the first 150 seconds after a LOCA. During this time, the containment shell would not have heated up enough to significantly affect the containment pressure. Prior to actuation of the fourth stage of the ADS there is limited communication between the containment and the RCS, and the fourth-stage ADS valves are adequately sized and are not sensitive to containment pressure.

In conclusion, the staff finds that Westinghouse has satisfied that part of Appendix K to 10 CFR Part 50 which requires a conservative backpressure to be used in ECCS reflood calculations. Westinghouse has also satisfied, in part, 10 CFR 50.46, inasmuch as the analysis used to calculate the containment backpressure is acceptable. In particular, Westinghouse has performed its minimum containment backpressure analysis, using assumptions that minimize the calculated backpressure and which are consistent with those assumptions acceptable to the staff, by following the guidance given in BTP CSB 6-1 of SRP Section 6.2.1.5. Furthermore, Westinghouse has followed the guidance given in SRP Section 6.2.1.5 regarding the mass and energy releases. Therefore, these releases are acceptable on the basis of the staff's findings in Section 15.2.6 of this report.

Westinghouse presented the mass and energy releases to the containment during the blowdown and reflood portions of the limiting, double-ended cold-leg break transient in DCD Tier 2, Table 6.2.1.5-1, as computed by the WCOBRA/TRAC code. The staff reviewed the application of this methodology to the AP1000.

On the basis of the aforementioned considerations, the staff finds the minimum containment backpressure analysis to be acceptable. The acceptability of the credited backpressure has been evaluated in the overall context of the ECCS performance capability studies. Section 15.2.6.5 of this report provides the staff's evaluation of the ECCS performance.

6.2.1.6 Testing and Inspection

Westinghouse summarizes the functional testing and inspection of the containment vessel in DCD Tier 2, Section 6.2.1.6. DCD Tier 2, Section 3.8.2.7, describes the testing and inservice inspection of the containment vessel, while DCD Tier 2, Section 6.2.3, describes isolation testing and DCD Tier 2, Section 6.2.5, describes leak testing. The valves of the PCS are periodically stroke tested, and DCD Tier 2, Section 6.2.2.4, provides a description of the testing and inspection. Testing and inspection will be consistent with regulatory requirements and guidelines.

The baffle between the containment vessel and the shield building is equipped with removable panels and clear observation panels to allow for inspection of the containment surface. DCD Tier 2, Section 3.8.2.7 provides the requirements for inservice inspection of the steel containment vessel. DCD Tier 2, Section 6.2.2.4, provides a description of the testing to be performed.

Westinghouse states that testing is not required on any subcompartment vent or on the collection of condensation from the containment shell. DCD Tier 2, Section 5.2.5, discusses the collection of condensate from the containment shell and its use in leakage detection.

The PCS is designed to permit periodic testing of system readiness, as specified in the TS.

Preoperational Testing

Preoperational testing of the PCS is verified to provide adequate cooling of the containment. The flow rates are confirmed at the minimum initial tank level, at an intermediate step with all but one standpipe delivering flow, and at a final step with all but two standpipes delivering to the containment shell. The flow rates are measured utilizing the differential pressure across the orifices within each standpipe, and will be consistent with the following minimum flow rates (see DCD Tier 2, Table 6.2.2-1), which are greater than the flow rates used in the safety analyses, assuring that the safety analyses are conservative:

- 1783.3 L/min (471.1 gpm) at the minimum operating water level
- 902.4 L/min (238.4 gpm) at a level after the first standpipe is uncovered
- 696.5 L/min (184.0 gpm) at a level after the second standpipe is uncovered
- 573.1 L/min (151.4 gpm) at a level after the third standpipe is uncovered

The containment PCS water coverage fraction (wetted surface area) will also be measured at the base of the upper annulus, in addition to the measurements at the spring line. A full-flow test, using the PCS water storage tank to deliver the flow, will be performed. An additional test will be performed at a lower flow rate using the PCS recirculation pumps to deliver the flow. A throttle valve will be used to obtain the low flow rate (less than the full capacity of the PCS recirculation pumps). This flow rate will be reestablished for subsequent tests over the life of the plant using the throttle valves. These two benchmark tests will be used to develop acceptance criteria for the TSs. The full-flow condition is selected because it is the most important flow rate with respect to the peak pressure; the lower flow rate is selected to verify the wetting characteristics of the containment exterior surface at less than full-flow conditions.

Engineered Safety Features

The standpipe elevations are verified to be at the values specified in DCD Tier 2, Table 6.2.2-2.

The inventory within the tank is verified to provide 72 hours of operation from the minimum initial operating water level with a minimum flow rate over the duration in excess of 381.2 L/m (100.7 gpm). The flow rates are measured utilizing the differential pressure across the orifices within each standpipe.

The containment vessel exterior surface, above the 41.2-m (135-ft) elevation, is verified to be coated with an inorganic zinc coating. The containment vessel interior surface, from 2.1 m (7 ft) above the operating deck, is verified to be coated with an inorganic zinc coating (see DCD Tier 2, Section 6.1.2.1.5).

The passive containment cooling airflow path will be verified at the following locations:

- air inlets
- base of the outer annulus
- base of the inner annulus
- discharge structure

With either a temporary water supply or the passive containment cooling ancillary water storage tank connected to the suction of the recirculation pumps, and with either of the two pumps operating, the flow rate to the PCCWST will be in excess of 381.12 L/min (100.7 gpm), as used in the safety analyses. Temporary instrumentation or changes in the PCCWST level will be utilized to verify the flow rates. The capacity of the passive containment cooling ancillary water storage tank is verified to be adequate to supply 381.2 L/min (100.7) gpm for a duration of 4 days.

The PCCWST provides makeup water to the spent fuel pool. When aligned to the spent fuel pool, the flow rate is verified to exceed 132.5 L/min (35 gpm). Installed instrumentation will be utilized to verify the flow rate. The volume of the passive containment cooling ancillary water storage tank is verified to exceed 2,952,621.2 liters (780,000 gallons).

DCD Tier 2, Chapter 14, provides additional details for preoperational testing of the PCS; Chapter 14 of this report discusses these details.

The staff finds that the preoperational testing program, in combination with the supplemental initial test program, adequately verifies the PCS water delivery flow rates, wetted surface areas, and volume of PCS water available. These tests verify the PCS characteristics used in the licensing analyses and are acceptable. DCD Tier 2, Section 14.2.9.1.4, "Passive Containment Cooling System Testing," describes the initial test program.

<u>Operational Testing</u>

Operational testing is performed to:

- Demonstrate that the sequencing of valves occurs on the initiation of Hi-2 containment pressure, and demonstrate the proper operation of remotely operated valves.

- Verify valve operation during plant operation. The normally open motor-operated valves (MOVs), in series with each normally closed air-operated isolation valve, are temporarily closed. This closing permits isolation valve stroke testing without actuation of the PCS.

- Verify waterflow delivery is consistent with the accident analysis.

- Verify visually that the path for containment cooling airflow is not obstructed by debris or foreign objects.

- Test frequency is consistent with the plant TSs (DCD Tier 2, Section 16.1, TS 3.6) and inservice testing program (DCD Tier 2, Section 3.9.6).

The operational testing program assures that the PCS is available and maintained consistent with the licensing analyses. The staff finds the operational testing program to be acceptable.

6.2.1.7 <u>Containment Instrumentation Requirements</u>

Instrumentation is provided to monitor the conditions inside the containment and to actuate the appropriate ESFs, should those conditions exceed the predetermined levels. As required by 10 CFR 50.34(f)(2)(xvii), instrumentation must be provided to measure, record, and provide readout in the control room of the following system parameters:

- containment pressure
- containment water level
- containment hydrogen concentration
- containment radiation intensity (high level)

In addition to these parameters, RG 1.97 recommends that instrumentation to monitor containment atmosphere and sump water temperature be provided. DCD Tier 2, Chapter 7, describes the AP1000 postaccident monitoring system considering the recommendations in RG 1.97. DCD Tier 2, Section 5.2.5, describes instrumentation to monitor RCS leakage into containment.

The containment pressure is measured by four independent pressure transmitters, and the signals are fed into the ESF actuation system, as described in DCD Tier 2, Section 7.3.1. Upon detection of high pressure inside the containment, the appropriate safety actuation signals are generated to actuate the necessary safety-related systems. If a low-pressure alarm exists, however, it does not actuate the safety-related systems.

The containment atmosphere radiation level is monitored by four independent area monitors located above the operating deck inside the containment building. The measurements are continuously fed into the ESF actuation system logic. DCD Tier 2, Section 11.5, provides information on the containment area radiation monitors, while DCD Tier 2, Section 7.3, describes the ESF actuation system operation.

The hydrogen concentration monitoring subsystem (HCMS) measures the containment hydrogen concentration but it is not part of postaccident monitoring and is non-safety related.

DCD Tier 2, Sections 6.2.4 and 7.5 describe the system, and Section 6.2.5.4 of this report presents the staff's evaluation. The staff concludes in Section 6.2.5.4 of this report that the HCMS design meets the requirements of GDC 41 and 10 CFR 50.44 as well as the provisions of draft RG 1.7, Revision 3.

DCD Tier 2, Table 7.5-1, "Post-Accident Monitoring System," contains the instrumentation provided to meet the guidance of RG 1.97. DCD Tier 2, Table 7.5-1, includes instrumentation capable of monitoring the atmospheric temperature of containment and the containment sump's water level and temperature in a harsh environment. Containment temperature is measured from 0–204 °C (32–400 °F). Containment water level can be monitored from the 21.95 m (72 ft) elevation to the 33.53 m (110 ft) elevation. The staff concluded that containment cooling status can be determined through an alternative means to direct reading of containment sump water temperature. The alternative means include either Category 2 PRHR HX inlet or outlet temperature. In the AP1000, containment sump water temperature is monitored as a Category 2 variable from 10–260 °C (50–500 °F) at the PRHR HX outlet.

The containment instrumentation described above has been designed to meet the guidance of Item II.F.1 of NUREG-0737 and RG 1.97. The staff concludes that this instrumentation meets the regulations and standards in SRP Section 6.2.1.1.A-I.G and 10 CFR 50.34(f)(2)(xvii).

6.2.1.8 <u>Adequacy of IRWST and Containment Recirculation Screen Performance</u>

DCD Tier 2, Section 6.3, provides information concerning the operation of the AP1000 PXS, which includes a description of the design features of the system's debris screens. The AP1000 has two sets of screens, the IRWST screens and the containment recirculation screens. DCD Tier 2, Section 6.3.2.2.7, includes a description of these screens, their design criteria, and their conformance with Revision 2 of RG 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident." As discussed in this section, the staff reviewed the AP1000 debris screens in accordance with the current state of knowledge concerning the issues associated with Generic Safety Issue (GSI) 191, "Assessment of Debris Accumulation on PWR Sump Performance." The NRC staff issued RAIs concerning the design adequacy of the IRWST and containment recirculation screens in a letter to the applicant dated January 21, 2003. The applicant submitted responses to the staff's RAIs as described in the evaluation below.

6.2.1.8.1 Post-LOCA Debris Generation and Washdown Potential

As the IRWST and containment recirculation screens are designed to accommodate only modest debris loadings, the AP1000 design relies heavily upon limiting the introduction of potential debris sources into containment and impeding debris transport to prevent unacceptably large debris loadings. A predominate source of postaccident debris in many reactor designs is the fibrous thermal insulation on piping and components of the RCS and other associated and colocated systems. In order to limit the challenge to the IRWST and containment recirculation screens from insulation debris, the applicant stated in DCD Tier 2, Section 6.3.2.2.7.1, that fibrous insulation will not be used in zones of the AP1000 containment where it would be vulnerable to damage by jet impingement from postulated pipe breaks.

DCD Tier 2, Section 6.3.2.2.7.1, originally defined the zones considered by the applicant to be vulnerable to damage by jet impingement in the following way:

> Insulation located in a spherical region within a distance equal to 12 inside diameters of the LOCA pipe break is assumed to be affected by the LOCA when there are intervening components, supports, structures, or other objects. In the absence of intervening components, supports, structures, or other objects, insulation in a cylindrical area extending out a distance equal to 45 inside diameters from the break along an axis that is a continuation of the pipe axis and up to 5 inside diameters in the radial direction from the axis is assumed to be affected by the LOCA.

The boundaries of these zones, from which fibrous material would be excluded, were based on calculations performed for the NRC staff by Science and Engineering Associates, Inc. (SEA), and data taken from tests performed by the Boiling Water Reactor Owners' Group (BWROG) and described in its utility resolution guidance report, NEDO-32686. In regions of containment where there are no intervening structures, the SEA calculations and BWROG tests show that fibrous insulation can be degraded into readily transportable pieces up to distances equivalent to 45 times the inner diameter of the ruptured pipe. Because the applicant's definition of the vulnerability zone for regions of containment that do not contain intervening materials is consistent with the testing and analysis described in this paragraph, the NRC staff finds it to be acceptable.

For containment regions in which jet impingement will be reflected and attenuated by intervening structures, the staff has previously considered a spherical jet impingement model to be a reasonable approximation for estimating a volume of generated debris. The NRC safety evaluation report (SER) on the BWROG's report NEDO-32686 states that a spherical impingement model appears logical for congested zones of containment, and that it may be the best approximation for estimating the amount of debris in congested zones. However, the SER also indicates that the precision of the spherical model is unsupported by either analytical modeling or experimental evidence.

Consistent with the SER on NEDO-32686, the NRC staff considers the spherical jet impingement model to have limited applicability for the AP1000. Specifically, the NRC staff agreed that systematically excluding fibrous insulation from spherical volumes (with a radius equal to 12 inside pipe diameters) surrounding postulated break locations will greatly minimize the amount of debris generated from fibrous insulation. However, the staff was unable to conclude that the applicant's controls regarding fibrous insulation will ensure that no debris would be generated from fibrous insulation by breaks in congested zones of containment.

As demonstrated in the citation above, DCD Tier 2, Section 6.3.2.2.7.1, models containment congestion as an all-or-nothing condition. It is unclear to the staff that such a binary model is capable of accurately predicting jet impingement for break locations with only mild or directional structural congestion. Under these conditions, for example, the shape of the jet impingement could resemble partially obstructed opposing cones that extend beyond the spherical boundary assumed in the DCD. Additionally, uncertainty exists relative to the spherical impingement model, even in areas of high structural congestion, because of possible variations in parameters, such as the offsets of ruptured pipes and the degree of intervening material present in the various directions about a pipe break. Thus, the staff expects that the zones actually affected by jet impingement would not be precisely spherical and concludes that portions of actual jet impingement boundaries could exceed 12 pipe diameters, even in the presence of intervening structures. For this reason, in the DSER, the staff concluded that the applicant had not sufficiently demonstrated that actual jet impingement zones, in the presence of intervening structures, would not result in the generation of debris from fibrous insulation that is located beyond a 12-pipe-diameter sphere. This was Open Item 6.2.1.8.1-1 in the DSER.

In a July 3, 2003, letter, the applicant provided a revised DCD Tier 2, Section 6.3.2.2.7.1, in which it increased the DCD spherical zone of damage from 12- to 20-pipe inside diameters. In addition, Westinghouse provided information that states that the only place where RCPB piping is located within 45-pipe inside diameters of fibrous insulation is near the top of the pressurizer. Here, chilled water lines are located at least 24-pipe inside diameters away from the RCPB piping. Because the applicant increased the spherical zone of damage from 12- to 20-pipe inside diameters and provided information that shows that, in the presence of intervening structures, actual jet impingement zones would not result in the generation of debris from fibrous insulation that is located beyond a 20-pipe-diameter sphere, the staff considers DSER Open Item 6.2.1.8.1-1 closed.

In zones vulnerable to jet impingement, the DCD states that the AP1000 will use reflective metallic insulation (RMI), or an equivalent material that will not be damaged by jet impingement or be transported to the containment recirculation screens. Testing sponsored by the NRC and the BWROG in the resolution of the boiling-water reactor (BWR) strainer blockage issue shows that the deployment of RMI within zones vulnerable to jet impingement will significantly reduce the likelihood of screen blockage in comparison to fibrous insulation. As compared to fibrous insulation, RMI is generally (1) more resistant to damage from jet impingement, (2) more difficult to transport to the debris screens, (3) less capable of accumulating uniformly on the screens, and (4) not known to interact with particulate debris in the same way that fibrous debris does (the so-called "thin-bed" effect) to result in a severe head loss across the screens.

As a result of the deployment of RMI (or an equivalent material) in zones vulnerable to jet impingement, DCD Tier 2, Section 6.3.2.2.7.1, states that, "fibrous debris is not generated by loss-of-coolant accidents." In regard to this statement, the staff issued RAIs 650.002, 650.003, and 650.004, which questioned whether the applicant had considered all potential sources of fibrous debris that could be present in the AP1000 containment in the design of the IRWST and recirculation screens. The staff's RAIs pointed out that, in addition to insulation, other sources of fibrous debris could be installed in containment (such as fire barriers), and that resident fibrous debris may exist in the form of dust on surfaces inside containment or as material settled onto the floor of the IRWST. To resolve the staff's concerns regarding these potential sources of fibrous debris, in a letter dated February 21, 2003, the applicant submitted analyses of the IRWST screens in RAI 650.004 and the containment recirculation screens in RAI 650.005 to demonstrate their capability to accommodate anticipated amounts of fibrous materials. The applicant's analyses are evaluated subsequently. Because the applicant's analyses of the AP1000 debris screens include debris from resident fibrous material, the staff considers RAI 650.002 (which concerned resident fibrous dust) to be closed. The staff will evaluate the adequacy of the applicant's treatment of the resident fiber concern in conjunction with RAIs 650.004 and 650.005.

The staff issued RAI 650.003 to determine whether the applicant had considered fire barriers as a potential source of postaccident debris. In a letter dated February 21, 2003, the applicant responded to RAI 650.003 by stating that the fire barriers intended for use in the AP1000 containment are made of steel plates or a steel-composite material. The applicant stated that no fibrous debris would be generated from this material, and that any debris formed would either be maintained within the steel plates or would have sufficient density to sink rapidly in water. After a teleconference with the staff on April 3, 2003, the applicant agreed to revise its response to this RAI to clarify that the prohibition on fibrous materials in zones vulnerable to jet impingement and containment flooding applies not only to fibrous insulation, but also to other installed sources of fibrous material (e.g., fire barriers and ventilation filters). In a letter dated April 9, 2003, the applicant confirmed the applicability of this prohibition to other installed sources of fibrous material by submitting a revised response to RAI 650.003 and revising DCD Tier 2, Section 6.3.2.2.7.1, appropriately. Because the applicant provided the additional information requested by the staff and revised the DCD to reflect its commitment to assure that fibrous material installed in containment will not become debris that could adversely affect the IRWST and containment recirculation screens, the staff considers RAI 650.003 closed.

Similar to its position concerning the AP600, the applicant maintained that coatings used in containment below the operating deck do not have to be qualified as safety-related for the AP1000 because their failure will not interfere with core cooling by clogging the IRWST and containment recirculation screens. As discussed in DCD Tier 2, Section 6.1.2.1.6, the non-safety-related coatings used in the containment will be procured (but not applied, inspected, or monitored) according to the quality assurance requirements of Appendix B to 10 CFR Part 50. On this basis, the applicant stated in its letter dated February 21, 2003, that the non-safety-related coatings are not expected to fail. Although it does not altogether disagree with this position, the staff has historically considered at least a partial failure of non-safety-related coatings to be credible, and included the failure of coatings in its evaluation (in Sections 6.2.1.8.2 and 6.2.1.8.3 of this report) of the adequacy of the IRWST and containment recirculation screens.

DCD Tier 2, Section 6.3.8.1, states that, "Combined License applicants referencing the AP1000 will address preparation of a program to limit the amount of debris that might be left in the containment following refueling and maintenance outages." Because a significant fraction of the debris (particularly with respect to fibrous debris) that eventually reaches the debris screens could be resident debris, the staff believes that a robust containment cleanup and foreign-material control program is essential to ensuring adequate performance of the AP1000 PXS. This program is addressed by COL Action Item 6.2.1.8.1-1.

The AP1000 design includes a non-safety-related containment spray system that will be used only in the case of a severe accident. Containment spray is capable of washing down debris that might not otherwise be transported to the containment pool and IRWST. However, if a severe accident has occurred, by definition, core heat removal or coolant has already been lost, and the containment spray's effect in transporting additional debris is not significant. Therefore, in comparison to operating PWRs, the fraction of debris washed down to the IRWST and containment pool is expected to be reduced.

As a result of the applicant's design controls to limit quantities of potential debris sources in containment, particularly in regard to sources of fibrous material, the staff concludes that the amount of debris generated for the AP1000 would be small compared to most operating PWRs. In addition, much of the debris that would be generated is known not to contribute significantly to head loss under conditions applicable to the AP1000. The following two sections provide the staff's assessment of the ability of the IRWST and containment recirculation screens to accommodate anticipated quantities of postaccident debris.

6.2.1.8.2 Pool Transport and Head Loss Evaluation of the IRWST Screens

DCD Tier 2, Section 6.3.2.2.7.2, originally described the IRWST screens as being flat, vertical screens, each 6.5 m^2 (70 ft^2) in area. The two screens are located at opposite ends of the IRWST, near the bottom of the tank. The screens are described as being designed to intercept debris larger than 0.3175 cm (0.125 in.), thereby preventing it from entering the RCS. The IRWST screens are each protected by a trash rack, which is designed to prevent large debris from reaching the fine screens. A debris curb at the base of the IRWST screens is designed to prevent high-density debris from being swept along the floor of the IRWST and upward onto the screen.

During normal operation, it is expected to be difficult for debris to enter the IRWST because normally closed louvers cover its vents and overflows from the containment atmosphere. In addition, the IRWST is constructed from stainless steel and will not generate the corrosion products that contributed to strainer plugging in the carbon steel suppression pools of operating BWRs. TS Surveillance Requirement (SR) 3.5.6.8 requires a visual inspection of the IRWST screens every 24 months to ensure that they are not restricted by debris. TS SR 3.5.4.7 requires a similar 24-month inspection of the IRWST gutters, which are covered by a trash rack and are part of the containment water long-term return and recirculation system. During accident conditions, limited quantities of debris may be introduced into the IRWST (e.g., through entrainment in the condensate washdown collected by the IRWST gutters). An example of a potential debris source cited in DCD Tier 2, Section 6.3.2.2.7.2, is the inorganic zinc coating applied to the inside surface of the containment shell. (However, the DCD states that, should any coating debris enter the tank, it would tend to settle onto the tank floor by virtue of its density.) Based on the limited potential for debris generation discussed previously and the limited availability of debris that would have the potential to wash down into the IRWST, the amount of debris introduced is expected to be relatively small.

In RAI 650.004, the staff requested additional information concerning the potential for debris to be concentrated in the IRWST when the tank inventory is cycled during refueling outages. Any debris entrained in water entering the IRWST would settle out during long stagnation periods during the operating cycle, and could later become stirred up during an accident condition when the ADS is actuated. In its response to RAI 650.004, dated February 21, 2003, the applicant stated that purification processes associated with refueling activities would limit the amount of debris that would be capable of settling out on the IRWST floor. The applicant further provided qualitative reasons to support its contention that, "any resident debris that has settled on the

IRWST floor prior to an accident is not likely to be stirred up by the ADS . . . .". Reasons cited by the applicant included the subcooled state of the IRWST inventory, the location of the ADS spargers 4.87 m (16 ft) above the IRWST floor and only on one side of the tank, and the sequencing of the ADS valves. Because the applicant did not provide a quantitative analysis of the turbulence conditions within the IRWST during an ADS actuation, the staff lacks a sound basis to conclude whether the relatively small velocities needed to entrain settled debris would not be exceeded. Although the staff concurs that large amounts of debris (i.e., quantities comparable to those found in a BWR suppression pool) are unlikely to be settled on the floor of the IRWST, without a flow analysis, the staff finds that the design of the IRWST screens should include the capability to accommodate resuspension of available quantities of debris settled onto the IRWST floor.

To address this issue, the applicant's February 21, 2003, response to RAI 650.004 also included an analysis of the IRWST screens' capability to accommodate debris accumulation. The staff's review of the applicant's analysis showed that the mass of resident debris assumed by the applicant (i.e., 227 kg (500 lb)) was consistent with estimates made for current generation PWRs in the GSI 191 parametric study (NUREG/CR-6772). However, the staff could not accept this analysis, primarily because the applicant assumed that a single-density value is valid for all density-dependent calculations involving resident fibrous debris. According to the physical properties of analyzed types of fibrous materials, potentially different density values may be required to correctly determine the settling velocity (i.e., the material density), to calculate a volume from the assumed mass (i.e., the "as-found" density), and to determine the thickness and porosity of the associated debris bed (i.e., the rubblized density). As a result of the applicant's single-density assumption, which deviated significantly from the material properties of the low-density fiberglass on which the head loss data referenced by the applicant were based, the NRC staff concluded that the calculation was unacceptable. During a teleconference on April 3, 2003, the applicant agreed to resubmit its response to RAI 650.004, in light of the staff's concern. Pending an acceptable resolution of this concern, the staff considered the capability of the AP1000 IRWST screens to accommodate anticipated debris loadings to be Open Item 6.2.1.8.2-1 in the DSER.

To support closure of the open item, the applicant described in its January 13, 2004, letter, a design change to the IRWST screens which increased the fine screen area by at least a factor of 2 (i.e., $\geq$ 13 m^2 (140 ft^2)) by using a folded screen design. An increased screen area will allow the screen to tolerate more debris and lowers the water velocity at the screen face.

Two COL Action Items are provided to ensure adequate containment cleanliness is maintained, and that the increased IRWST surface area can accommodate anticipated debris loadings. DCD Tier 2, Section 6.3.8.1 (COL Action Item 6.2.1.8.1-1), "Containment Cleanliness Program," states the following:

> The Combined License applicants referencing the AP1000 will address preparation of a program to limit the amount of debris that might be left in the containment following refueling and maintenance outages. The cleanliness program will limit the storage of outage materials (such as temporary scaffolding and tools) inside containment during power operation consistent with [DCD Tier 2, Section] 6.3.8.2.

DCD Tier 2, Section 6.3.8.2 (COL Action Item 6.2.1.8.2-1), "Verification of Water Sources for Long-Term Recirculation Cooling Following a LOCA," states the following:

> The Combined License applicants referencing the AP1000 will perform an evaluation consistent with Regulatory Guide 1.82, revision 3, and subsequently approved NRC guidance, to demonstrate that adequate long-term core cooling is available considering debris resulting from a LOCA together with debris that exists before a LOCA. As discussed in DCD [Tier 2, Section] 6.3.2.2.7.1, a LOCA in the AP1000 does not generate fibrous debris due to damage to insulation or other materials included in the AP1000 design. The evaluation will consider resident fibers and particles that could be present considering the plant design, location, and containment cleanliness program. The determination of the characteristics of such resident debris will be based on sample measurements from operating plants. The evaluation will also consider the potential for the generation of chemical debris (precipitants). The potential to generate such debris will be determined considering the materials used inside the AP1000 containment, the post accident water chemistry of the AP1000, and the applicable research/testing.

Based on the increased screen size, in concert with the cleanliness program in COL Action Item 6.2.1.8.1-1, the minimal fibrous materials used in containment, and the other screen design features described in the DCD (trash racks, etc.) and discussed above, the staff considers the capability of the AP1000 IRWST screens to accommodate anticipated debris loadings to be acceptable. COL Action Item 6.2.1.8.2-1 will address any impact on the ability of the IRWST screens to accommodate anticipated debris loadings identified during the resolution of GSI 191, and that those impacts can be addressed using programmatic means. Therefore, the staff considers Open Item 6.2.1.8.2-1 closed.

6.2.1.8.3 Pool Transport and Head Loss Evaluation of the Containment Recirculation Screens

DCD Tier 2, Section 6.3.2.2.7.3, originally described the containment recirculation screens as being flat, vertical screens, each 6.5 m^2 (70 ft^2) in area. The screens are designed to intercept debris larger than 0.3175 cm (0.125 in.), thereby preventing it from entering the RCS. The screens are each protected by a trash rack, which is designed to prevent large debris from reaching the fine screens. The bottoms of the screens are elevated 0.61 m (2 ft) above the adjacent floor, which inhibits debris transport, much like a curb. The floor adjacent to the recirculation screens is at an elevation 3.5 m (11.5 ft) above the lowest elevation in containment. Each screen is protected from settling debris by a steel screen plate that extends outward 3 m (10 ft) in front of the screen, and 2.13 m (7 ft) to its side. The screen plates are specifically designed to prevent debris from the failure of protective coatings from approaching and potentially blocking the screens. TS SR 3.5.6.8 requires visual inspection of the recirculation screens every 24 months to ensure that they are not restricted by debris.

The low transport velocities of the AP1000, and the long time (i.e., up to 5 hours) before the recirculation mode of the passive core cooling system is initiated, will provide ample opportunity for dense debris to settle on the containment floor before suction is taken on the recirculation screens. Thus, it is unlikely that debris very much denser than water would reach the recirculation screens. In addition, the low transport velocities in the containment pool, in conjunction with the height of the recirculation screens, make it difficult for dense debris to reach and accumulate uniformly on the screen surface. The low flow velocities at the screen surface, which are typically an order of magnitude lower than the screen flow velocities at operating PWRs, also lead to reduced head losses. In addition, when the recirculation lines initially open, the water level in the IRWST is higher than the level in containment, and water flows from the IRWST backwards through the containment recirculation screens. This backflow tends to flush debris located on or near the recirculation screens away from the screens.

The water level at the beginning of recirculation is approximately 3 m (10 ft) above the top of the recirculation screens. Thus, any floating debris will remain clear of the screens. The recirculation piping inlet elevation is slightly above the compartment floor, which is substantially below the expected postaccident flood-up water level. This reduces the potential for air ingestion because recirculation does not initiate until the flood-up water level is well above the piping inlet.

The water level in containment following a LOCA would be sufficiently high that DCD Tier 2, Section 3.4.1.2.2.1, states that inventory from the containment pool would "flow back into the RCS via the break location . . . ." In light of this statement, the staff issued RAI 650.001 to request additional information concerning the potential for entrained debris to cause blockage at flow restrictions within the RCS, once flow begins entering through the break location after floodup (i.e., bypassing the recirculation screens). In a letter dated February 21, 2003, the applicant responded to RAI 650.001 by submitting an analysis which concluded that RMI debris is incapable of causing such blockage. Although the applicant's response partially addressed the staff's RAI, it was not complete because it did not address the potential for other sources of debris, such as fibrous debris and floatable debris, to enter the RCS through the break location and block requisite core cooling flowpaths. Pending the complete resolution of this concern, the staff considered debris blockage in the RCS to be Open Item 6.2.1.8.3-1 in the DSER.

In the applicant's Revision 1 response to RAI 650.001 dated April 24, 2003 (which was also cited as the initial response to Open Item 6.2.1.8.3-1 on June 23, 2003), the applicant expanded its evaluation of potential sources of debris to include resident fibrous and particle debris, floatable debris, and unqualified coating debris. With regard to particle and floatable debris, the applicant stated that such debris may be close to the density of water such that it would remain suspended for sufficient time to allow transport into the RCS through a pipe break that becomes flooded. The applicant estimated that the pressure drop across the debris to be about 6.9 kPa (1 psi). The applicant did not expect floatable debris to be a factor because the pressure in the RCS would exceed the containment pressure by several psi at the time that the containment water level passes the break elevation. With regard to unqualified coatings, the applicant stated that the high specific gravity (>1.3) would promote the settling of such debris. Even if some coating debris entered the RCS, the applicant stated that it is expected this debris would settle in the lower plenum of the reactor vessel.

The staff had a conference call with the applicant on June 26, 2003, to discuss this open item, as well as related Open Items 6.2.1.8.2-1, 6.2.1.8.3-2, and 6.2.1.8.3-3. The staff discussed the pressure drop calculations across the debris bed in the reactor core, as well as across the containment sump screens and IRWST screens. In addition, the staff asked the applicant why the face velocity of the water calculated at the protective grid was not consistent with the face velocity of the water calculated at the containment sump screens. The applicant committed to review its calculations and made these calculations available to the staff for audit.

The staff had an additional conference call with the applicant on July 29, 2003 to discuss the four open items referenced above. The applicant acknowledged a need to further review their calculations. The applicant submitted Revision 1 to Open Item 6.2.1.8.3-1 in a letter dated August 13, 2003, which provided the results of its revised calculation of the pressure loss across a debris bed located in the core. The revised calculation was based on a total of 226 kg (500 lb) of resident debris located inside containment, a portion of which was assumed, based on engineering judgement, to bypass the screens and enter the RCS. The calculation also used the BLOCKAGE code to calculate the head loss across the screens. The applicant also performed sensitivity studies with variations in amounts of debris transported to the screens and in the mass ratio of fiber versus particle debris. The applicant concluded that the bounding pressure loss through resident debris that might deposit on the lower core support plate or in the core would not reduce the flow to the core.

Subsequent to an audit of the calculations by the staff, the staff had a conference call with the applicant on August 19, 2003. The staff discussed the applicant's calculations and the assumptions in the BLOCKAGE code with the applicant. Subsequent to this conference call, the applicant submitted Revision 2 to Open Item 6.2.1.8.3-1 in a letter dated September 8, 2003. The applicant revised its calculations further and included additional sensitivity studies. The maximum pressure drop across the core was indicated to be less than 6.9 kPa (1 psi). In addition, the applicant proposed to Revise DCD Tier 2, Sections 6.3.8.1 and 6.3.8.2, which describe COL action items for a containment cleanliness program and verification of containment resident particulate debris characteristics.

As stated in Section 6.2.1.8.2 of this report, the staff's review of the applicant's analysis showed that the mass of resident debris assumed by the applicant (i.e., 227 kg (500 lb)) was consistent with estimates made for current generation PWRs in the GSI 191 parametric study (NUREG/CR-6772). However, the staff could not accept this analysis, primarily because the applicant assumed that a single-density value is valid for all density-dependent calculations involving resident fibrous debris. According to the physical properties of analyzed types of fibrous materials, potentially different density values may be required to correctly determine the settling velocity (i.e., the material density), to calculate a volume from the assumed mass (i.e., the "as-found" density), and to determine the thickness and porosity of the associated debris bed (i.e., the rubblized density). As a result of the applicant's single-density assumption, which deviated significantly from the material properties of the low-density fiberglass on which the head loss data referenced by the applicant were based, the NRC staff concluded that the calculation was unacceptable.

The staff notes that the applicant has committed to two COL action items which require the COL applicant to prepare a containment cleanliness program (COL Action Item 6.2.1.8.1-1) and evaluate that adequate long-term cooling is available considering the debris resulting from a LOCA in conjunction with debris that exists before a LOCA using RG 1.82, Revision 3, and subsequently approved NRC guidance (COL Action Item 6.2.1.8.2-1). The staff has found these two COL action items to be acceptable as discussed below and in Section 6.2.1.8.2 of this report.

Based on the design changes to the recirculation screens discussed in this section, in concert with the cleanliness program in COL Action Item 6.2.1.8.1-1, the minimal fibrous materials used in containment, and the other screen design features described in the DCD, the staff considers the capability of the AP1000 reactor core to accommodate anticipated debris loadings to be acceptable. Therefore, Open Item 6.2.1.8.3-1 is resolved.

In RAI 650.006, the staff questioned whether non-safety-related coatings inside the containment could disbond and subsequently block the containment recirculation screens. In a letter dated February 21, 2003, the applicant responded to RAI 650.006 by submitting calculations of the trajectories of settling paint particles to provide confidence that the particles are incapable of passing around the protective screen plate and blocking a significant fraction of the recirculation sump screen surface. The applicant's RAI response further stated that no coating debris can approach the recirculation screens without passing around the protective plates because coatings are not permitted on the surfaces inside the plates. ITAAC commitment 8.c(x) in DCD Tier 1, Table 2.2.3-4, states that the applicant will verify that the dry film density of non-safety-related coating materials is consistent with the assumed value in the settling calculation (i.e., ≥ 1600 kg/m^3 (100 lb/ft^3)). The particle sizes and settling rates assumed in the applicant's calculation are similar to or more conservative than those previously accepted by the staff in its review of the AP600 (NUREG-1512) and the Comanche Peak Steam Electric Station Units 1 and 2 (NUREG-0797, Supplement No. 9, dated March 1985). However, according to recent evidence that resident fibrous material may exist in containments, and considering operational experience and test data concerning coating failures, the staff considers that paint particles significantly smaller than 200 mils in diameter could become trapped in the interstitial locations of a fibrous debris bed and contribute to the blockage of the recirculation screens. Therefore, in a teleconference on April 3, 2003, the staff requested additional justification from the applicant to support the assumption that paint particles smaller than 200 mils are not a blockage concern for the containment recirculation screens. The staff considers the response to RAI 650.006 to be an open item pending the resolution of this concern. This was Open Item 6.2.1.8.3-2 in the DSER.

In an April 24, 2003, letter, the applicant provided more information on the justification behind the selection of 200 mils wide and 5 mils thick as the minimum coating debris size. This is the smallest particle size that would be trapped by the screen; smaller particles would pass through a clean screen and the fuel assemblies. The applicant acknowledged that smaller particles could be trapped in a fibrous debris bed, but stated that this potential impact is compensated by two effects. The first effect is that smaller diameter particles have a faster settling rate because the reduction in the "flutter" effect, which slows the settling of discs that have a higher diameter-to-thickness ratio. A faster settling rate will allow more particles to settle out prior to reaching the screens. The second effect is that the large protective plate over the screens will protect screens from those particles with much slower-than-expected settling rates and which support passive HX operation. The staff finds the justification behind the assumption that paint particles smaller than 200 mils are not a blockage concern for the containment recirculation screens to be acceptable because the two effects described above decrease the potential that smaller particles will become trapped in a fibrous bed on the screens. The staff considers Open Item 6.2.1.8.3-2 closed.

The staff's review found that insufficient information was available in the DCD to determine whether the containment recirculation screens are capable of tolerating anticipated postaccident debris loadings. Therefore, in RAI 650.005, the staff requested additional information from the applicant to determine the debris-blockage failure criterion of the containment recirculation screens. The applicant responded to RAI 650.005 in a letter dated February 21, 2003, by providing an analysis intended to demonstrate that the AP1000 recirculation screens could accommodate a mass of resident debris (i.e., 227 kg (500 lb)) that is equivalent to estimates made for current generation PWRs in the GSI 191 parametric study (NUREG/CR-6772). However, the staff could not accept this analysis, primarily because the applicant assumed that a single-density value is valid for all density-dependent calculations regarding resident fibrous debris. According to the physical properties of analyzed types of fibrous materials, potentially different density values may be required to correctly determine the settling velocity (i.e., the material density), to calculate a volume from the assumed mass (i.e., the as-found density), and to determine the thickness and porosity of the associated debris bed (i.e., the rubblized density). As a result of the applicant's single-density assumption, which deviated significantly from the material properties of the low-density fiberglass on which the head loss data referenced by the applicant were based, the NRC staff concluded that the calculation was unacceptable. During a teleconference on April 3, 2003, the applicant agreed to resubmit its response to RAI 650.005, in light of the staff's concern. Pending an acceptable resolution of this concern, the staff considered the capability of the AP1000 containment recirculation screens to accommodate anticipated debris loadings to be Open Item 6.2.1.8.3-3 in the DSER.

The applicant described in its January 13, 2004, letter, two design changes to the recirculation screens. The first design change increased the fine screen area by at least a factor of 2 (i.e., ≥ 13 m^2 (140 ft^2)) by using a folded screen design. An increased screen area will allow the screen to tolerate more debris and lowers the water velocity at the screen face. The second design change added a cross-connection pipe between the two recirculation screens. Based on the above design changes to the recirculation screens, in concert with the cleanliness program in COL Action Item 6.2.1.8.1-1, the minimal fibrous materials used in containment, and the other screen design features described in the DCD, the staff considers the capability of the AP1000 recirculation screens to accommodate anticipated debris loadings to be acceptable. The staff feels that COL Action Item 6.2.1.8.2-1 will capture any impact on the ability of the recirculation screens to accommodate anticipated debris loadings identified during the resolution of GSI 191, and that those impacts can be addressed using programmatic means. The staff considers DSER Open Item 6.2.1.8.3-3 closed.

The applicant described in its January 13, 2004, letter, a design change to the IRWST screens which increased the fine screen area by at least a factor of 2 (i.e., ≥ 13 m^2 (140 ft^2)) by using a folded screen design. An increased screen area will allow the screen to tolerate more debris and lowers the water velocity at the screen face.

Two COL Action Items are provided to ensure adequate containment cleanliness is maintained, and that the increased recirculation surface area can accommodate anticipated debris loadings. DCD Tier 2, Section 6.3.8.1 (COL Action Item 6.2.1.8.1-1) states the following:

The Combined License applicants referencing the AP1000 will address preparation of a program to limit the amount of debris that might be left in the containment following refueling and maintenance outages. The cleanliness program will limit the storage of outage materials (such as temporary scaffolding and tools) inside containment during power operation consistent with [DCD Tier 2, Section] 6.3.8.2.

DCD Tier 2, Section 6.3.8.2 (COL Action Item 6.2.1.8.2-1) states the following:

The Combined License applicants referencing the AP1000 will perform an evaluation consistent with Regulatory Guide 1.82, revision 3, and subsequently approved NRC guidance, to demonstrate that adequate long-term core cooling is available considering debris resulting from a LOCA together with debris that exists before a LOCA. As discussed in DCD [Tier 2, Section] 6.3.2.2.7.1, a LOCA in the AP1000 does not generate fibrous debris due to damage to insulation or other materials included in the AP1000 design. The evaluation will consider resident fibers and particles that could be present considering the plant design, location, and containment cleanliness program. The determination of the characteristics of such resident debris will be based on sample measurements from operating plants. The evaluation will also consider the potential for the generation of chemical debris (precipitants). The potential to generate such debris will be determined considering the materials used inside the AP1000 containment, the post accident water chemistry of the AP1000, and the applicable research/testing.

Based on the increased screen size, in concert with the cleanliness program in COL Action Item 6.2.1.8.1-1, the minimal fibrous materials used in containment, and the other screen design features described in the DCD (screen elevation above the adjacent floor, etc.) and discussed above, the staff considers the capability of the AP1000 recirculation screens to accommodate anticipated debris loadings to be acceptable. COL Action Item 6.2.1.8.2-1 will address any impact on the ability of the recirculation screens to accommodate anticipated debris loadings identified during the resolution of GSI 191, and that those impacts can be addressed using programmatic means. Therefore, the staff considers Open Item 6.2.1.8.2-1 closed.

During the development of Revision 3 to RG 1.82, the staff identified concerns related to additional debris that can be caused by chemical reactions in the containment. In a letter dated November 12, 2003, the staff requested that the applicant address the following chemical effects as they relate to the responses to Open Items 6.2.1.8.2-1, 6.2.1.8.3-1, and 6.2.1.8.3-3:

- To minimize potential debris caused by chemical reaction of the pool water with metals in the containment, exposure of bare metal surfaces (e.g., scaffolding) to containment cooling water through spray impingement or immersion should be minimized either by removal or by chemical-resistant protection (e.g., coatings or jackets).

- In addition to debris generated by jet forces from the pipe rupture, debris created by the resulting containment environment (thermal and chemical) should be considered in the analyses. Examples of this type of debris would be disbondment of coatings in the form of chips and particulates or formation of chemical debris (precipitants) caused by chemical reactions in the pool.

The staff considered the chemical effects described above as they relate to debris generation to be Open Item 6.2.1.8.3-4.

In its November 26, 2003, response to Open Item 6.2.1.8.3-4, the applicant explained that the AP1000 is designed such that there should not be a need for temporary scaffolding during outages. In addition, large storage areas outside of containment eliminate the need for storage of outage material in containment. The applicant revised DCD Tier 2, Section 6.3.8.1 to have the containment cleanliness program limit the storage of outage material in containment. Also, the applicant explained that its preferred approach is to use materials that do not need coatings or have permanent coatings to minimize coating disbondment.

The applicant also revised DCD Tier 2, Section 6.3.8.2 to include the evaluation of chemical debris. The staff feels that COL Action Item 6.2.1.8.2-1 will capture any impact on the ability of the affected components to accommodate anticipated debris loadings identified during the resolution of GSI 191 due to chemical effects, and that those impacts can be addressed using programmatic means. The staff considers Open Item 6.2.1.8.3-4 closed.

6.2.1.8.4 Conclusions

The staff completed its review of the adequacy of the performance of the IRWST and recirculation screen in light of anticipated postaccident debris loadings. The staff finds that debris screen performance has been acceptably addressed for the AP1000 PXS.

6.2.2 Containment Heat Removal Systems

In accordance with GDC 38, the system employed by the AP1000 to remove heat from the containment atmosphere under postulated DBA conditions is the PCS. As described in DCD Tier 2, Section 6.2.2, the purpose of the system is to prevent the containment from exceeding its design temperature and pressure, thereby maintaining containment integrity and reducing the driving force for postaccident radioactive releases to the environment. This function is accomplished in the PCS by evaporative and natural convective cooling, and to a lesser degree, by radiative heat transfer.

The PCS is a seismic Category 1, Westinghouse Class C system designed to Section III, Class 3 standards of the ASME Code, in accordance with RGs 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and 1.29, "Seismic Design Classification." As stated in DCD Tier 2, Section 6.2.2, the principal safety design bases of the PCS include the following:

- to maintain the containment internal pressure below the design value for 3 days following a DBA, without operator action

- to withstand a single failure of an active component, assuming the loss of all onsite or offsite power, without losing the ability to perform its intended safety function

- to design components necessary for accident mitigation to remain functional during, and to withstand the effects of, a DBA

A distinguishing feature of the PCS is that it relies on naturally occurring passive physical phenomena to perform its cooling function. After initial actuation, the system does not depend on any active components. This is in contrast to existing Westinghouse designs, which utilize containment sprays and safety-grade fan coolers to cool the containment. These existing systems make use of active components, including ac-powered pumps and fans.

The major components of the PCS are the primary containment vessel, which acts as the safety-grade interface to the ultimate heat sink, the shield building, PCCWST, the air baffle, air inlets, and air diffuser, and the water distribution system comprising a water distribution bucket and distribution weirs. Section 6.2.3 of this report discusses the design of the shield building.

PCS operation is initiated when the containment pressure exceeds the Hi-2 setpoint value. Upon actuation from a safety-grade signal, water from the PCCWST flows through redundant isolation valves and a flow control orifice to the water distribution bucket. The redundant series valves are the only active components in the system, and consist of a fail-open (fail-safe), AOV and a normally open, dc-powered, MOV. Further redundancy is achieved by providing three trains of piping from the PCCWST to the distribution bucket, such that a failure in one train will not affect system performance. The PCCWST has a usable capacity of 2,864,420 liters (756,700 gallons) and is filled with demineralized water.

The water distribution bucket serves to uniformly distribute water on the outside of the primary containment vessel. The bucket is supported from the roof of the shield building and is suspended above the primary containment. Water is delivered to the containment vessel via evenly spaced slots surrounding the top perimeter of the bucket. A system of weirs and collection troughs installed directly on the vessel is also provided to further aid in uniform water distribution. The resulting water film flows under the force of gravity over the exterior of the containment vessel and is evaporated by heat conducted through the vessel wall, thereby removing energy from the post-DBA containment atmosphere. Unevaporated water is collected by two floor drains at the upper annulus elevation, each with 100-percent capacity, and routed to storm drains.

The baffle wall of the PCS is structurally supported by the primary containment and is located between that structure and the shield building, thus defining two annular flowpaths. In the event of a DBA, heat removed from the containment atmosphere through the vessel wall heats the air in the annular flowpath adjacent to the exterior vessel wall, thereby reducing the air density. Air inlets at the top of the shield building are permanently open to the atmosphere, and provide a path for ambient air to enter the annular region between the shield building wall and baffle. The difference in air density in the two annular regions results in a natural circulation flow from the air inlets to the bottom of the baffle wall, and up past the exterior of the containment vessel. The resulting natural convective cooling of the containment vessel assists in removing heat from the post-DBA containment atmosphere. The air/water vapor mixture exits to the atmosphere through a diffuser at the top of the shield building.

In DCD Tier 2, Section 6.2.2, Westinghouse states that the air inlets and air diffuser have been designed so that any external wind effects will only aid the natural air circulation (a "wind-positive" design). Westinghouse further states that these structures have been designed to prevent against ice and snow buildup, and to prevent the introduction of foreign debris into the airflow path.

The staff addresses the ability of the PCS to perform its intended safety function in Section 6.2.1.1 of this report.

6.2.3 Shield Building Functional Design

The AP1000 containment design incorporates a shield building that comprises the structure and annulus that completely surrounds the primary containment vessel. This building is a cylindrical, reinforced concrete structure with a conical roof that supports the water storage tank and air diffuser (or chimney) of the PCS. It shares a common basemat with the primary containment and auxiliary building, and is designed as a seismic Category 1 structure, in accordance with RG 1.26. It has an inner radius of about 20 m (70 ft), a height of 83.3 m (273.25 ft), and a thickness of 0.9 m (3 ft) in the cylindrical section.

The two primary functions of the shield building during normal operation are to provide a barrier from radioactive systems and components inside containment to shield against radiological effects, and to protect the primary containment from external events, such as tornados and tornado-produced missiles. Under DBA conditions, the shield building serves as a key component of the PCS by aiding in the natural convective cooling of the containment.

The key structural features of the shield building are the cylindrical structure, roof structure, and lower, middle, and upper annulus areas. Additionally, the design includes the air inlets, inlet plenum, water storage tank, air diffuser, and air baffle, all functioning as part of the PCS, which is described in Section 6.2.2 of this chapter. The cylindrical section of the shield building acts as a major structural component for the complete nuclear island and supports the PCS water storage tank. Flooring and walls of the auxiliary building are also connected to the cylindrical section of the shield building. Section 3.8 of this report provides the staff's evaluation of the containment and shield building.

6.2.4 Containment Isolation System

The CIS consists of isolation barriers, such as valves, blind flanges, and closed systems, and the associated instrumentation and controls required for the automatic or manual initiation of containment isolation. The purpose of the CIS is to permit the normal or postaccident passage of fluids through the containment boundary, while protecting against release of fission products to the environment that may be present in the containment atmosphere and fluids as a result of postulated accidents.

In DCD Tier 2, Section 6.2.3, Westinghouse provides a description of the CIS. The AP1000 has been designed to minimize the number of mechanical containment penetrations (including hatches). Also, a greater percentage of the penetrations are normally closed, and those that are normally open use fail-close valves for isolation.

The staff reviewed the description of the containment isolation system using the review guidance and acceptance criteria of Section 6.2.4 of the SRP. SRP Section 6.2.4 identifies the staff's review methodology and acceptance criteria for evaluating compliance with GDC related to those piping systems penetrating containment.

The staff's review encompassed the following areas specified by Section 6.2.4 of the SRP and 10 CFR 50.34(f)(2)(xiv):

- CIS design, including:
  - the number and location of isolation valves (e.g., the isolation valve arrangements, location of isolation valves with respect to the containment wall, purge and vent valve conformance to BTP CSB 6-4, and instrument line conformance to RG 1.11)
  - the actuation and control features for isolation valves
  - the normal positions of valves, and the positions valves take in the event of failures
  - the initiating variables for isolation signals, and the diversity and redundancy of isolation signals
  - the basis for selecting closure time limits for isolation valves
  - the redundancy of isolation barriers
  - the use of closed systems as isolation barrier substitutes for valves
- the protection provided for CISs against loss of function caused by missiles, pipe whip, and natural phenomena
- environmental conditions in the vicinity of CISs and equipment and their potential effect
- the mechanical engineering design criteria applied to isolation barriers and equipment
- the provisions for alerting operators of the need to isolate manually controlled isolation barriers
- the provisions for, and TS pertaining to, operability and leak rate testing of isolation barriers
- the calculation of containment atmosphere released prior to isolation valve closure for lines that provide a direct path to the environs

- containment purging/venting requirements of 10 CFR 50.34(f)(2)(xiv)

The following sections provide a discussion of the staff's findings and conclusions for each of the above review areas.

6.2.4.1 Number, Location, and Arrangement of Isolation Valves

The regulatory requirements relating to number, location, and arrangement of isolation valves serving containment piping penetrations are specified in GDC 55, "Reactor Coolant Pressure Boundary Penetrating Containment," GDC 56, "Primary Containment Isolation," and GDC 57, "Closed System Isolation Valves." GDC 55 and 56 require two isolation valves, one inside and one outside containment, per penetration, and the valves must be locked closed or automatic, with the restriction that a simple check valve may not be used as an automatic valve outside containment. GDC 57, which applies to penetrations for which there is a closed system inside containment, requires one locked closed, automatic (but not simple check) or remote manual isolation valve outside containment. The staff reviewed Westinghouse's proposed use of containment isolation valves, as described in DCD Tier 2, Table 6.2.3-1, for conformance with these GDC. The staff reviewed the valve arrangement information for each penetration and confirmed that the number, location, and arrangement conform to the acceptance criteria. DCD Tier 2, Table 6.2.3-1, identifies the penetrations. Each penetration has an isolation device both inside and outside containment, except for the secondary coolant system isolation lines. The exception for SG (secondary coolant system) piping is typical of PWRs and is acceptable based on credit for use of the secondary coolant system piping as a closed system inside the containment, thereby satisfying the requirements of GDC 57.

6.2.4.2 Actuation and Control Features for Isolation Valves

An SRP provision and TMI (Item II.E.4.2) requirement, in accordance with 10 CFR Section 50.34(f)(2)(xiv)(A), requires that all nonessential systems be automatically isolated upon initiation of an appropriate containment isolation signal. Nonessential systems are generally those which are neither ESF systems nor systems which accomplish a function similar to an ESF system. However, non-ESF and non-safety-grade systems should be classified as essential, if their continued operation under postaccident conditions will improve the reliability of a safety function.

The staff reviewed the actuation and control features (e.g., automatic, manual, or remote manual) for each isolation device. All AP1000 containment penetrations will be closed during an accident, with the exception of the normal residual heat removal (RHR) lines, which are normally closed, and would be opened by operator action during the first 2 hours of an accident. The review confirmed that the other valves will be provided with locking devices and administrative controls (as defined in SRP Section 6.2.4) to ensure that they are normally closed, or will be provided with automatic closure controls. Normally closed, nonautomatic isolation valves have provisions for locking the valves in the closed position. Administrative controls, as well as the design of locking devices, verify that nonautomatic isolation valves are in the correct position during plant operation.

The actual stem position of each power-operated isolation valve, whether remote, manual, or automatic, is indicated in the control room and provided as input to the plant computer. A means for position indication for these valves is also provided locally at the valves. Automatic isolation devices are provided with reset features to prevent automatic return to the normal position when an isolation signal clears.

Isolation valves that must be operable following a DBA or SSE are powered by the Class 1E dc power system. Manual override and signal reset of isolation signals is provided for such valves. Consistent with the requirements of TMI Item II.E.4.2 (as invoked by 10 CFR 50.34(f)(2)(xiv)), the design of isolation instrumentation precludes the capability for ganged reopening of closed isolation valves. All overpressure relief valves used as containment isolation valves comply with the SRP acceptance criterion of having a setpoint greater than or equal to 150 percent of the containment design pressure.

TMI Item II.E.4.2 requires that the design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action. The design bases for the AP1000 CIS (see DCD Tier 2, Section 6.2.3.5) include this requirement.

6.2.4.3 Normal and Fail Positions of Isolation Valves

The acceptance criterion in Section 6.2.4 of the SRP states that, upon loss of actuator power, automatic valves should take the position that provides greater safety. The staff reviewed the normal and fail positions of isolation devices indicated in DCD Tier 2, Table 6.2.3-1. The staff's *review confirmed that nonmotor-operated automatic isolation devices fail in the closed position* upon loss of power source (air or electrical power). MOVs are powered by Class 1E dc power, and fail in the as-is position. A single power system failure will not prevent closure of both isolation valves in a containment penetration. These features ensure single-failure-proof isolation capability for all penetrations that might be opened during operation.

TMI Item II.E.4.2 states that containment purge and vent valves must be verified closed at least every 31 days. The TSs assure compliance with this requirement.

6.2.4.4 Initiating Variables for Isolation, Diversity, and Redundancy of Isolation Signals

Various instrumentation signals are used for automatic initiation of containment isolation. The following ESF-grade signals initiate closure of containment isolation valves, as indicated in DCD Tier 2, Table 6.2.3-1:

- A containment isolation signal (DCD Tier 2, Section 7.3.1.2.1) is generated from any of the following monitored variables:

  - automatic or manual safeguards actuation signal
  - manual containment isolation actuation
  - manual actuation of the PCS signal

- A safeguards actuation signal (DCD Tier 2, Section 7.3.1.1) is initiated by any one of the following monitored variables:

  — low pressurizer pressure
  — low lead-lag, compensated steamline pressure
  — low reactor coolant inlet temperature
  — Hi-2 containment pressure
  — manual initiation

- A steamline isolation signal (DCD Tier 2, Section 7.3.1.2.10) is initiated by any of the following monitored parameters:

  — Hi-2 containment pressure
  — low reactor coolant inlet temperature
  — low lead-lag, compensated steamline pressure
  — high steamline pressure negative rate
  — manual initiation

- A main feedwater isolation signal (DCD Tier 2, Section 7.3.1.2.6) is generated by any of the following monitored parameters:

  — *automatic or manual safeguards signal actuation*
  — manual initiation
  — Hi-2 SG narrow-range level
  — Low-1 T_{AVG} with coincident P4 permissive
  — Low-2 T_{AVG} with P4 permissive

- A startup feedwater isolation signal (DCD Tier 2, Section 7.3.1.2.13) occurs as the result the following conditions:

  — low T_{COLD} in any loop
  — Hi-2 SG narrow-range water level in either SG
  — manual actuation of main feedwater isolation

- A SG blowdown isolation signal (DCD Tier 2, Section 7.3.1.2.11) is used for SG blowdown line isolation and is initiated by either of the following parameters:

  — PRHR HX alignment signal
  — Low narrow-range SG water level

- An automatic isolation of the normal residual heat removal (RNS) system containment isolation valve (DCD Tier 2, Section 7.3.1.2.20 is initiated by the following:

  — Hi-2 containment radioactivity
  — automatic or manual safeguards actuation signal which is used in conjunction with a safeguards signal and provides diversity for RNS system isolation
  — manual initiation

The isolation signal, as a result of the automatic or manual safeguards actuation, can be manually reset to block the isolation of the RNS to permit RNS operation after a safeguards signal.

- A containment air filtration system isolation signal (DCD Tier 2, Section 7.3.1.2.19) is initiated by the following:
  - automatic or manual safeguards actuation signal
  - manual actuation of containment isolation
  - manual actuation of passive containment cooling
  - Hi-1 containment radioactivity

The non-safety-grade diverse actuation system (DAS) signal (DCD Tier 2, Section 7.7.1.11) is also used for automatic containment isolation. The DAS is a non-safety-related instrumentation system that provides diverse backup to support risk goals.

RG 1.141, "Containment Isolation Provisions for Fluid Systems," and TMI Item II.E.4.2 state that CIS designs shall have diversity in the parameters sensed for the initiation of containment isolation, in accordance with SRP Section 6.2.4, "Containment Isolation System." The staff's review verified that the diversity requirement is met.

TMI Item II.E.4.2 states that the containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions. It further states—

> The pressure setpoint selected should be far enough above the maximum expected pressure inside the containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or fluctuations due to the accuracy of the pressure sensor. A margin of 6.9 kPa (1 psi) above the maximum expected containment pressure should be adequate to account for instrument error. Any proposed values greater than 6.9 kPa (1 psi) will require detailed justification. Applicants for an operating license should use pressure history data from similar plants that have operated more than one year, if possible, to arrive at a minimum containment setpoint pressure.

Westinghouse indicated a containment isolation actuation pressure of less than or equal to 156.5 kPa (8 psig) for the AP1000 TSs. All applicable DBA analyses used this setpoint. However, a reviewer's note in the AP1000 TSs states that the 156.5 kPa (8 psig) value (given in brackets) is included for reviewer information only, and that the actual setpoint for a plant will be determined using a setpoint methodology that incorporates NRC-accepted setpoint methodology. The reviewer's note further states that the pressure setpoint should be specified as low as reasonable, without creating potential for spurious trips during normal operations, consistent with TMI Item II.E.4.2.

TMI Item II.E.4.2 states that containment purge and vent isolation valves must close on a high-radiation signal. The AP1000 containment air filter supply and exhaust isolation valves comply with this requirement for additional isolation signal diversity.

As indicated in the above discussion, the initiating variables and the diversity and redundancy of the AP1000 instrumentation provide a reliable means for automatic containment isolation for DBA conditions and meet the acceptance criteria of SRP Section 6.2.4. See Chapter 7 of this report for additional discussion of instrumentation.

6.2.4.5 Basis for Selection of Closure Time Limits

Westinghouse stated that the AP1000 isolation times will be consistent with the performance of standard valve operators, except where shorter limits are necessary. Shorter limits are required for containment vent and purge valves and MSIVs, and have been included in the AP1000 design. For valve sizes up to 30.5 cm (12 in.), the standard valve operator closure times of ANS-56.2-1976 are consistent with the 60-second criterion of Section 6.2.4 of the SRP. For larger valves, Westinghouse specified appropriate faster limits. These limits are consistent with assumptions and criteria for radiological dose analyses and ECCS analysis (reflood backpressure) assumptions. Westinghouse's proposed closure time limits are, therefore, acceptable.

6.2.4.6 Redundancy of Isolation Barriers

Section 6.2.4.1 of this report discusses the staff's review of redundancy for valved piping penetrations. The AP1000 containment design incorporates the following nonvalved penetrations for purposes other than permitting fluid passage into and out of the containment during normal or accident conditions:

- the fuel transfer tube
- three spare penetrations
- two personnel hatches
- an equipment hatch
- a maintenance hatch

In addition to the valved penetrations, DCD Tier 2, Table 6.2.3-1, also lists these penetrations.

The personnel air locks have redundant barriers, one of which may be opened while the other is closed. This permits personnel passage into and out of containment during plant operation. The barriers are interlocked to ensure that both doors are not opened simultaneously. Each door is provided with a testable seal.

For penetrations that are not expected to be opened during normal or accident conditions, a single isolation barrier (e.g., blind flange) is provided. Such penetrations include the equipment and maintenance hatches, fuel transfer tube, and spare penetrations. These single-barrier penetration closures are not subject to single-active failures during plant operation. A double-seal gasketing arrangement provides a means for testing, and is therefore acceptable.

6.2.4.7 Use of Closed Systems as Isolation Barriers

The SG secondary side, as bounded by the main steam, feedwater, and blowdown isolation valves, is a closed system inside containment. This feature eliminates the need for inboard containment isolation valves in the steam, feed, and blowdown lines because the SG tubes and tube sheet and secondary-system piping actually serve as a containment boundary. The SG piping penetrating containment (e.g., main steamlines) is, however, provided with isolation valves for the purpose of limiting the severity of reactor cooldown transients and to serve as a second isolation barrier. The isolation provisions for the closed system configuration conform to the criteria of GDC 57, which require a single isolation valve located outside containment, and are, therefore, acceptable.

6.2.4.8 Protection of Containment Isolation Systems against Loss of Function As a Result of Missiles, Pipe Whip, and Natural Phenomena

The staff confirmed that the CIS design bases include protection from missiles, pipe breaks, earthquakes, fire, internal and external flooding, ice, wind, and tornados. Other sections of this report discuss specific features and design criteria for the protection of systems, structures, and equipment from these phenomena.

6.2.4.9 Environmental Conditions in the Vicinity of Containment Isolation Components

Containment isolation equipment may be subject to potentially harsh conditions resulting from pressure, temperature, flooding, jet impingement, radiation, missile impact, and seismic response. The staff review confirmed that the CIS has been properly classified to ensure that protection from these environmental hazards is encompassed by the mechanical and electrical design bases and quality standards of the isolation system. Section 3.11 of this report discusses the staff's review of the environmental qualification of the AP1000 SSCs, including containment isolation equipment.

6.2.4.10 Mechanical Engineering Design Criteria Applied to the Containment Isolation System, Structure, and Components

The CIS will be designed to ASME Section III, Class 2 criteria. Containment penetrations are classified as Quality Group B, as defined in RG 1.26, and seismic Category 1. The containment penetrations, including valves and the steam and feedwater system inside containment, are identified as Class B, equivalent to ANS Safety Class 2. Westinghouse has selected the appropriate mechanical design classification for the CIS.

6.2.4.11 Provisions for Alerting Operators of the Need to Actuate Manual Isolation Devices in the Event of an Accident

Manual operator action is not relied upon for closure of containment isolation devices that may be normally or intermittently open during power operation. There are no piping penetrations used for circulation of contaminated coolant outside containment during accident conditions.

6.2.4.12 Provisions for and TSs Pertaining to Operability and Leakage Rate Testing of Isolation Barriers

In order to permit periodic Type A, Type B, and Type C testing of the containment and its piping penetrations, special connections must be provided on the containment and on penetrations to permit application and measurement of test air pressure and venting of leakage air. The staff's review confirmed that test, vent, and drain connections are provided at suitable locations. Section 6.2.6 of this report provides the staff's evaluation of the AP1000 containment leakage testing program.

6.2.4.13 Calculation of Containment Atmosphere Released before Isolation Valve Closure for Lines that Provide a Direct Path to the Environs

The largest piping penetration that provides a direct path to the atmosphere is the 40.65-cm (16-in.) containment air filtration exhaust line. The isolation valves in this line are specified as having a 10-second closure time. This closure time is consistent with the assumptions and criteria for radiological dose analyses and the ECCS analysis (reflood backpressure) assumptions used in DCD Tier 2, Chapter 15. Westinghouse's proposed closure time limits are, therefore, acceptable.

6.2.4.14 TMI Item II.E.4.4, Vent/Purge Valve Positions

The bases for TS 3.6.3 indicate that the 40.65-cm (16-in.) containment air filtration valves will be opened as needed in Modes 1, 2, 3, and 4. The staff's position is that the opening of large valves that provide a direct path from the containment atmosphere to the environs should be minimized during power operation. The staff also notes that the plant design has very few safety-related items in containment that would require containment entry while at power. Therefore, venting or purging should occur infrequently. As a result, the containment vent/purge system should only be used for containment pressure control, as low as is reasonably achievable, or air quality considerations for personnel entry, or TS surveillances. TS SR 3.6.3.1 includes this restriction.

6.2.4.15 Conclusions

The staff has determined that the CIS meets the acceptance criteria of Section 6.2.4 of the SRP, including the NUREG-0737 TMI action plan items incorporated into 10 CFR 50.34.

6.2.5 Containment Combustible Gas Control

The AP1000 DSER stated the following:

> The AP1000 DCD for the control of combustible gas in containment during accidents does not comply with current regulations.
>
> The NRC has proposed major changes to 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors," and related changes to 10 CFR 50.34 and 10 CFR 52.47, along with the creation of a

> new rule, 10 CFR 50.46a (see 67 FR 50374, August 2, 2002). These proposed changes are meant to risk-inform the combustible gas control requirements, and constitute significant relaxations of the requirements. The staff plans to finalize the rule changes during 2003.
>
> The AP1000 DCD is written in anticipation of these rule changes. As such, it is not in compliance with the current, more restrictive regulations. Furthermore, until the proposed rule changes are final and effective, the staff cannot know for certain if the DCD will comply with the revised rule. Therefore, the issue of containment combustible gas control must remain open at this time. This is DSER Open Item 6.2.5-1.

Subsequent to the publication of the DSER, the NRC has revised its regulations regarding the control of combustible gas in containment. The revised regulations were published on September 16, 2003, and became effective on October 16, 2003. The NRC has extensively revised 10 CFR 50.44, "Combustible Gas Control for Nuclear Power Reactors," made associated changes to 10 CFR 50.34 and 10 CFR 52.47, and added a new section, 10 CFR 50.46a, "Acceptance Criteria for Reactor Coolant System Venting Systems." The revisions apply to current power reactor licensees, and consolidate combustible gas control regulations for future power reactor applicants and licensees. The revised rules eliminate the requirements for hydrogen recombiners and hydrogen purge systems and relax the requirements for hydrogen- and oxygen-monitoring equipment to make them commensurate with their risk significance.

In more detail, the NRC is retaining existing requirements for ensuring a mixed atmosphere, inerting BWR Mark I and II containments, and maintaining hydrogen control systems capable of accommodating an amount of hydrogen generated from a metal-water reaction involving 75 percent of the fuel cladding surrounding the active fuel region in BWR Mark III and PWR ice condenser containments. The NRC is eliminating the design-basis LOCA hydrogen release from 10 CFR 50.44, and consolidating the requirements for hydrogen and oxygen monitoring into 10 CFR 50.44. At the same time, it is relaxing safety classifications and licensee commitments to certain design and qualification criteria. The NRC is also relocating and rewording, without materially changing, the hydrogen control requirements in 10 CFR 50.34(f) to 10 CFR 50.44. The high point vent requirements are being relocated from 10 CFR 50.44 to a new 10 CFR 50.46a, with a change that eliminates a requirement prohibiting the venting of the RCS if it could "aggravate" the challenge to containment.

The staff is now able to complete its review of containment combustible gas control and close DSER Open Item 6.2.5-1.

Combustible gas within the AP1000 containment is controlled by the containment hydrogen control system. This system consists of the hydrogen ignition subsystem, the non-safety-related hydrogen recombination subsystem, and the hydrogen concentration monitoring subsystem.

The containment hydrogen control system serves the following functions:

- hydrogen concentration monitoring
- hydrogen control during and following degraded core or core melt scenarios (provided by hydrogen igniters)

In addition, two non-safety-related passive autocatalytic recombiners (PARs) are provided for defense-in-depth protection against the buildup of hydrogen following a LOCA.

The hydrogen ignition subsystem meets the requirements of 10 CFR 50.44 for future water-cooled reactors. The design must limit hydrogen concentrations in containment during and following an accident that releases an equivalent amount of hydrogen as would be generated from a 100-percent, fuel clad-coolant reaction, uniformly distributed, to less than 10 percent (by volume), and maintain containment structural integrity and appropriate accident-mitigating features. This requirement was promulgated to address the lessons learned from the TMI accident. This type of accident is considered beyond the design basis and will be referred to as the severe accident case in this section. In the severe accident case, the hydrogen generation from the fuel clad-coolant reaction could be sufficiently rapid that it may not be possible to prevent the hydrogen concentration in the containment from exceeding the lower flammability limit. The hydrogen ignition subsystem is designed to promote hydrogen burning soon after the lower flammability limit is reached in the vicinity of an igniter. Initiation of hydrogen burning at the lower level of hydrogen flammability will prevent combustion at higher hydrogen concentrations, and provides confidence that containment structural integrity can be maintained during hydrogen burns.

6.2.5.1 Hydrogen Ignition Subsystem

For severe accident hydrogen control, the AP1000 containment has been provided with 64 hydrogen igniters. The igniter assembly is designed to maintain the surface temperature within a range of 870 °C to 927 °C (1600 °F to 1700 °F) in the anticipated containment environment following a LOCA. A spray shield is provided to protect the igniter from falling water drops (resulting from condensation of steam on the containment shell and on nearby equipment and structures).

The igniters have been divided into two power groups. Power to each group will be normally provided by offsite power. However, should offsite power be unavailable, then each of the power groups is powered by one of the onsite nonessential diesels. Finally, should the diesels fail to provide power, then the non-Class 1E batteries for each group will support approximately 4 hours of igniter operation. Assignment of igniters to each group is based on at least one igniter from each group providing coverage for each compartment or area.

The hydrogen ignition subsystem has been designed to promote hydrogen burning at a low concentration. Igniters have been placed in the major regions of the containment where hydrogen may be released, through which it may flow, or where it may accumulate. DCD Tier 2, Table 6.2.4-6, provides the criteria used in the evaluation and the application of the criteria to specific compartments. DCD Tier 2, Figures 6.2.4-5 through 6.2.4-13, provide the location of igniters throughout containment. DCD Tier 2, Table 6.2.4-7, also summarizes the location of igniters, and identifies subcompartment/regions and which igniters by power group provide protection. The locations identified are considered approximations (± 1 m (2.5 ft)), with the final locations governed by the installation details.

The staff's review of the number and location of igniters focused on the major transport paths of hydrogen inside the containment to ensure that hydrogen can be burned close to the release point. One of the release paths considered was through the IRWST via the first three stages of the ADS. Two igniters are located within the IRWST below the tank roof of the IRWST and above the spargers. In the event of hydrogen releases from the spargers, the igniters directly above the release points will provide the most immediate point of recombination. In the event that the IRWST is hydrogen rich and air is drawn into the IRWST, the mixture will become flammable. To provide for this type of recombination, the two inlet vents, on the PRHR side of the IRWST, have each been fitted with an igniter. Should the environment within the IRWST be inerted or otherwise not be ignited by the assemblies above the sparger, the hydrogen can be ignited as it exhausts from the IRWST at any of four vents fitted with igniter assemblies.

Flow from the IRWST vents, located at Elevation 41.15 m (135 ft), exhausts into the upper compartment. Igniter coverage for the upper compartment includes 10 igniters at Elevations 49.4 m–53.64 m (162 ft–176 ft), 4 igniters at Elevation 69.5 m (228 ft), and 4 igniters at Elevation 78.33 m (257 ft).

Another important flowpath is through the fourth stage of the ADS which relieves, at Elevation 34.1 m (112 ft), into the SG compartments. Hydrogen flow into the SG compartment will be burned by two igniters at Elevation 36.58 m (120 ft) and 2 igniters at Elevation 42.37 m (139 ft). Hydrogen leaving the SG compartment is burned in the upper compartment. This flowpath would also apply to hydrogen released through any RCS break in the SG compartment.

Finally, the staff verified that the 15 major regions or compartments identified by Westinghouse in DCD Tier 2, Tables 6.2.4-6 and 6.2.4-7 had at least two igniters, and they included the enclosed areas within containment. Two enclosed areas, the reactor cavity and the north chemical and volume control system (CVS) equipment room, do not have igniter coverage or do not have igniters directly over the RCS piping. Hydrogen releases within the reactor cavity will flow either through the vertical access tunnel, through the opening around the RCS hot- and cold-legs into the loop compartments, or, if the refueling cavity seal ring fails, then potentially through the refueling cavity. Each of these adjacent regions or compartments has at least four igniters. The staff concludes that igniter coverage of the reactor cavity is not required because (1) the reactor cavity would most likely be flooded either through the break or by the cavity flooding system, (2) adequate igniter coverage is available in hydrogen pathways from the reactor cavity, and (3) any maintenance or inspection would result in elevated personnel exposure.

Although igniters have not been located directly over the RCS piping in the north CVS room, two igniters have been located near the ceiling of the equipment room between the equipment module and the major relief paths from the compartment. The staff finds this exception from the igniter location criteria in DCD Tier 2, Table 6.2.4-6 of DCD Tier 2 to be acceptable.

On the basis of the staff's review and Westinghouse's implementation of the igniter location criteria as listed in DCD Tier 2, Table 6.2.4-6 the staff concludes that adequate igniter coverage has been provided.

An additional consideration is the potential of generating significant concentration gradients within the containment during the course of the event. The staff does not expect significant stratification within the AP1000 containment based on the containment-mixing evaluation (below) and the number and location of igniters provided for the AP1000 containment.

The hydrogen ignition subsystem has been identified as one of the systems to be included in the equipment survivability program. DCD Tier 2, Appendix 19D and Appendix D to the AP1000 PRA discuss equipment survivability; Section 19.2.3.3.7 of this report evaluates this feature.

The hydrogen ignition subsystem conforms to the requirements of 10 CFR 50.44 by providing reasonable assurance that uniformly distributed hydrogen concentrations inside containment will not exceed 10 percent by volume.

6.2.5.2 Hydrogen Recombination Subsystem

The staff used the requirements of 10 CFR 50.44 to review the hydrogen recombination subsystem in the AP1000 design.

The hydrogen recombination subsystem, in the AP1000 design, serves no safety-related function, and therefore, has no nuclear safety design basis. The subsystem consists of two non-safety-related PARs installed inside the containment above the operating deck at approximate elevations of 49.4 m (162 ft) and 50.6 m (166 ft) respectively, each about 3.96 m (13 ft) inboard from the containment shell. The PARs recombine hydrogen and oxygen in the containment atmosphere to make water at a rate too slow to remove hydrogen from the containment atmosphere quickly enough to be of significant benefit during a severe accident. The PARs are provided for defense-in-depth protection against the buildup of hydrogen following a LOCA.

Based on its review, the staff finds that the hydrogen recombination subsystem is a non-safety-related system and serves no safety-related function, and its failure does not lead to the failure of any safety systems. The staff, therefore, concludes that the requirements of 10 CFR 50.44 are met, because hydrogen recombiners or similar systems are not required to control combustible gases during a design-basis LOCA. Based on the above, and the fact that its failure will not prevent safe shutdown, the staff finds the hydrogen recombination subsystem to be acceptable.

6.2.5.3 Containment Atmosphere Mixing

Another requirement of 10 CFR 50.44 for future water-cooled reactors is that all containments must have a capability for ensuring a mixed atmosphere during design-basis and significant beyond-design-basis accidents.

In meeting the requirements of 10 CFR 50.44 to provide the capability for ensuring a mixed atmosphere in the containment, and the requirements of GDC 41 to provide systems as necessary to ensure that containment integrity is maintained, a system (active, passive, or a combination of the two) should be provided to mix the combustible gases within the containment during design-basis and significant beyond-design-basis accidents. An analysis should be presented that demonstrates that excessive stratification of combustible gases will not occur within the containment or within a containment subcompartment. The containment internal structures should have design features that promote the free circulation of the atmosphere. An analysis of the effectiveness of these features for convective mixing should be presented. This analysis is acceptable if it shows that combustible gases will not accumulate within a compartment or cubicle to a level that supports combustion or detonation which could cause loss of containment integrity. As discussed below, the applicant has done this for the AP1000.

The AP1000 relies on natural circulation currents enhanced by the passive containment cooling system (PCS) to inhibit stratification of the containment atmosphere. DCD Tier 2, Appendix 6A discusses the physical mechanisms of natural circulation mixing that occur in the AP1000. Steam generated by decay heat can vent into the containment atmosphere in the form of a jet plume through the postulated break or the fourth stage of the ADS. The interaction of the plume with the ambient atmosphere can be described in terms of entrainment flow induced by the plume. Entrainment flow results in the mixing of ambient atmosphere with the steamflow in the plume. The plume will rise to the containment dome where the steam will be condensed on the inner surface of the containment shell, and the resulting cooler, denser air will fall to the operating deck.

Westinghouse provided an estimate of the degree of mixing by calculating the volumetric flow rates of gas entrained by a rising buoyant plume associated with steam generated by decay heat. The calculations were made on the basis of a steam production rate corresponding to decay heat at 1 hour and 24 hours into the accident. Entrainment flow rates were calculated using equations presented in an article by Peterson in Volume 37, Supplement 1, of the International Journal of Heat and Mass Transfer, entitled, "Scaling and Analysis of Mixing in Large Stratified Volumes." In the Westinghouse estimate, no credit was taken for cold plumes falling from the containment dome, which causes further circulation above the operating deck. Westinghouse estimated the circulation time constant at 1 hour to be 340 seconds, and at 24 hours to be 462 seconds. The staff performed confirmatory calculations of this methodology during its AP600 review using the same equations as Westinghouse, but with containment atmospheric conditions calculated by the staff, which indicated that the estimates were reasonable. The staff, therefore, is assured that the AP1000 estimates are also reasonable.

Westinghouse has arranged containment structures to promote mixing via natural circulation. Two general characteristics have been incorporated into the design of the AP1000 to promote mixing and eliminate dead-end compartments. The compartments below deck are large open volumes with relatively large interconnections, which promote mixing throughout the below-deck region. All compartments below deck are provided with openings through the top of the compartment to eliminate the potential for a dead pocket of high hydrogen concentration.

The accumulator and CVS compartments and the reactor cavity, including the reactor coolant drain tank room, do not participate in the natural circulation flow because they are dead-ended or filled with water. The IRWST compartment is essentially sealed at the vents by flappers after blowdown. The CVS and IRWST compartments are included as confined volumes that may have water pools that provide a source of hydrogen. However, each volume has igniters which will prevent excessive hydrogen buildup. The other compartments are either completely water filled or do not contain a significant pool of water for hydrogen generation. The staff finds that these compartments will not accumulate combustible gases to a level that supports combustion or detonation, which could cause loss of containment integrity.

In its analysis, Westinghouse assumed that the fission products and hydrogen released to the containment following a postulated design-basis LOCA are homogeneously distributed in the containment atmosphere within the open compartments that participate in natural circulation. The staff finds this assumption to be reasonable. This finding is based on (1) the ability of the PCS to enhance the condensation of steam and the entrainment of air inside containment, (2) analyses performed by Westinghouse, using a method confirmed by the staff, which show that the containment atmosphere above the operating deck is recirculated approximately every 8 minutes, 24 hours after a LOCA, (3) containment structures that have been arranged to promote mixing by means of natural circulation, and (4) CVS and IRWST compartments that have been provided with igniters.

6.2.5.4 <u>Hydrogen Concentration Monitoring Subsystem</u>

To satisfy the design requirements of GDC 41, combustible gas control system designs should include instrumentation needed to monitor system or component performance under normal or accident conditions. As stated in 10 CFR 50.44(c)(4)(ii), the equipment for monitoring hydrogen must be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond-design-basis accident for accident management, including emergency planning.

Draft RG 1.7, Revision 3 (ADAMS Accession No. ML031670912, Attachment 5, dated July 24, 2003), says that non-safety-related, commercial-grade hydrogen monitors can be used to meet these criteria if they comply with the following:

- Category 3 design and qualification criteria of RG 1.97 for monitors used as diagnostic or backup indicators
- Category 2 power source design and qualification criteria, as specified in Table 1 of RG 1.97

Table 1 of RG 1.97, Revision 3, dated May 1983, states that a Category 2 power source is a "high-reliability power source, not necessarily standby power." A Category 3 power source has no specific provisions associated with it.

The HCMS, as described in DCD Tier 2, Sections 6.2.4 and 7.5, consists of three non-Class 1E sensors. The sensors are placed in the upper dome where bulk hydrogen concentration can be monitored.

Hydrogen concentration is continuously indicated in the MCR. Additionally, high-hydrogen concentration alarms are provided in the MCR. The sensors are designed to provide a rapid response detection of changes in the bulk containment hydrogen concentration, and have a measurement range from 0 to 20 percent hydrogen. The response time of the sensor is at least 90 percent in 10 seconds.

The HCMS meets the guidance of RG 1.97 for Category 3 instruments, as described in DCD Tier 2, Section 7.5, and evaluated in Section 7.5 of this report. Further, the hydrogen sensors are powered by the non-Class 1E dc and uninterruptible power supply (UPS) system, which the staff considers to be a high-reliability power source.

The equipment survivability assessment also includes the HCMS. DCD Tier 2, Appendix 19D and Appendix D to the AP1000 PRA discuss equipment survivability; Section 19.2.3.3.7 of this report evaluates this feature.

The staff concludes that the HCMS design meets the requirements of GDC 41 and 10 CFR 50.44, as well as the provisions of draft RG 1.7, Revision 3.

6.2.5.5 Conclusions

The staff has determined that the containment hydrogen control system meets the requirements of GDC 41 and 10 CFR 50.44, as well as the guidelines of draft RG 1.7, Revision 3. DSER Open Item 6.2.5-1 is closed.

6.2.6 Containment Leakage Testing

The applicant's top level description of the proposed containment leakage rate testing program for AP1000 facilities is described in DCD Tier 2, Section 6.2.5 and in the proposed TSs of DCD Tier 2, Chapter 16. The test program will conform to the requirements of 10 CFR Part 50, Appendix J. The staff reviewed the information in the DCD for conformance to 10 CFR Part 50, Appendix J, and to GDC 52, "Capability for Containment Leakage Rate Testing," GDC 53, "Provisions for Containment Testing and Inspection," and GDC 54, "Piping Systems Penetrating Containment." GDC 52 requires the containment and associated equipment to be designed such that the periodic containment integrated leakage rate tests can be conducted at containment design pressure. GDC 53 requires that the containment allow periodic inspection, surveillance, and testing of certain systems, structures, and components. GDC 54 requires piping systems penetrating containment to have leak detection, isolation, and containment capabilities having appropriate redundancy, reliability, and performance capabilities, and with the capability for periodic testing of isolation valve operability and leakage rate. The staff used the guidance, staff positions, and acceptance criteria of SRP Section 6.2.6 and RG 1.163, "Performance-Based Containment Leak-Test Program," in conducting its review.

Each COL applicant will develop a "Containment Leakage Rate Testing Program" as specified in DCD Tier 2, Section 6.2.5 and by AP1000 TS 5.5.8. This program will identify which Option of Appendix J will be implemented. Option A provides prescriptive requirements, and Option B provides performance-based requirements. This program will also identify the specific TS surveillance requirements and test criteria for containment leakage rate tests. This is COL Action Item 6.2.6-1.

The applicant based the proposed TS in DCD Tier 2, Chapter 16 on Appendix J Option B, which is the Option more likely to be chosen by a COL applicant.

The staff review of the AP1000 containment leakage rate testing program encompassed the following review areas, as identified in SRP Section 6.2.6:

- Type A (integrated) leakage rate testing, including pretest requirements, general test methods, acceptance criteria for preoperational and periodic leakage rate tests, provisions for additional testing in the event of failure to meet acceptance criteria, and scheduling of tests.

- Containment penetration local (Type B) leakage rate testing, including identification of containment penetrations, general test methods, test pressures, acceptance criteria, and scheduling of tests.

- Containment isolation valve local (Type C) leakage rate testing, including identification of isolation valves, general test methods, test pressures, acceptance criteria, and scheduling of tests.

- Proposed TSs requirements pertaining to containment leakage rate testing.

The staff's findings for each of the above areas are discussed below. See also the staff's evaluation of the ITAAC in Chapter 14 of this report.

6.2.6.1 <u>Containment Integrated Leakage Rate Type A Tests</u>

Type A tests serve to provide assurance that the containment leakage rate, in the event of an accident, will not exceed the values assumed in the analyses of the radiological consequences of DBAs. An initial preoperational Type A test will be performed prior to initial startup, and periodic Type A tests and postrepair tests will be performed thereafter.

<u>Pretest Requirements for Type A Tests</u>

The DCD confirms that each Type A test will include the following pretest actions:

- A general containment inspection (internal and external) will be conducted of accessible areas. Any structural deformation or structural deterioration will be repaired before the Type A test; otherwise, the Type A test will be conducted in an as-found condition (i.e., before maintenance on valves, gaskets, seals, etc.).

- Isolation valves will be placed in their accident position using the normal method of operation, unless placement in that position is unsafe or impractical.

- Portions of fluid systems penetrating containment, that are part of the RCS boundary and that are open to the containment atmosphere under LOCA conditions, will be vented to the containment atmosphere.

- Portions of systems inside containment that penetrate containment and could rupture under LOCA conditions will be vented to the containment atmosphere and drained of fluid (unless the system would be watersealed or operating during an accident) to expose the isolation valves to the pressurized containment atmosphere.

- Components, such as tanks and instrumentation, inside containment will be vented to the containment atmosphere or removed from the containment, as necessary, to protect them against the effects of test pressure, or to preclude leakage that could affect the accuracy of the Type A test.

- Test conditions will be allowed to stabilize for at least 4 hours before beginning the test.

Compliance with the above satisfies the pretest requirements of Appendix J.

Test Method for Type A Tests

The DCD indicates that, consistent with ANSI/ANS-56.8-1994, Type A tests will use the "absolute" method and the "mass point" method. The containment will be pressurized with clean dry air to a pressure of P_a. P_a is the calculated peak containment internal pressure for the design-basis LOCA. The accuracy of the test will be verified by a supplemental test using methodology consistent with ANSI/ANS-56.8-1994. This test methodology is in accordance with the requirements of Appendix J to 10 CFR Part 50 and the guidance of RG 1.163, "Performance-Based Containment Leak-Test Program."

A permanently installed, non-safety-related piping system will be provided to facilitate controlled pressurization and depressurization of the containment. Portable compressors will be temporarily connected to the piping system for testing.

Test Acceptance Criteria

The maximum allowable leakage rate (L_a) is 0.10 percent of the containment air weight per day at P_a. During the first startup following testing, the leakage rate acceptance criterion will be 0.75 L_a, which is in accordance with the provisions of Appendix J to 10 CFR Part 50, SRP Section 6.2.6, and RG 1.163. The allowable leakage rate of 0.10 percent per day is consistent with the value used in analyses of the radiological consequences of a LOCA, as cited in DCD Tier 2, Table 15.6.5-2, and is consistent with the provisions of Section 6.2.6 of the SRP. It is, therefore, an acceptable leakage rate.

Provisions for Additional Testing in the Event of Failure to Meet Acceptance Criteria

ANSI/ANS-56.8-1994 specifies appropriate leakage pathway isolation, repair, and adjustment criteria to assure that overall as-found and as-left measurements are accurately determined to the extent possible, and without the need for test termination and a subsequent retest. If any

Type A test fails to meet the test acceptance criteria, the test schedule for subsequent tests will be adjusted in accordance with the requirements of the containment leakage rate testing program.

Scheduling of Type A Tests

An initial preoperational Type A test will be performed before initial power operation. Periodic Type A tests will be scheduled in accordance with the containment leakage rate testing program.

6.2.6.2 Containment Penetration Leakage Rate Type B Tests

Type B tests are intended to detect or measure the leakage rate across pressure-retaining or leakage-limiting boundaries other than containment isolation valves.

Identification of Containment Penetrations

Type B penetrations incorporate features such as resilient seals, gaskets, or bellows. The following four containment penetration types will receive preoperational and periodic Type B tests:

(1) penetrations having resilient seals, gaskets, or sealant compounds
(2) air locks and associated door seals
(3) maintenance and equipment hatches and associated seals
(4) electrical penetrations

These Type B penetrations include 1 main equipment hatch, 2 personnel air locks, 1 fuel transfer tube, 1 maintenance hatch, 32 electrical penetration assemblies, and 3 spare electrical penetration assemblies.

General Test Methods

The DCD states that the test boundary will be pressurized with air or nitrogen using local test connections. The pressure decay or flow meter makeup flow rate test methods will be used for leakage rate measurement.

Test Pressures

In the DCD, Westinghouse states that the test pressure will not be less than P_a.

Acceptance Criteria

In the DCD, Westinghouse states that the Type B leakage rate test results will be combined with the Type C results, in accordance with Appendix J to 10 CFR Part 50. The combined Types B and C acceptance criterion is 0.6 L_a. In addition, air lock chambers and individual doors must meet the specific leakage rate acceptance criteria identified in the TSs.

Scheduling of Tests

The schedules for periodic Type B leak rate tests will be in accordance with the containment leakage rate testing program to be developed by each COL applicant.

6.2.6.3 Containment Isolation Valve Leakage Rate Tests

Type C tests measure containment piping penetration/isolation valve leakage rates.

Identification of Isolation Valves Subject to Type C Testing

Valves at the containment boundary in SG and associated secondary-system piping will not be Type C tested, but the closed system inside containment will be tested with the containment (i.e., during Type A testing, the SG secondary side will be vented to the atmosphere outside containment). The requirements of 10 CFR Part 50, Appendix J, Option A, paragraph II.H identify those isolation valves included under Type C testing requirements; paragraph II.H.4 requires Type C testing for the containment isolation valves in main steam, feedwater, and similar piping of boiling-water reactors, but not pressurized-water reactors. For Option B of Appendix J to 10 CFR Part 50, RG 1.163 and ANSI/ANS-56.8-1994 provide similar guidance. Since the AP1000 is a pressurized-water reactor, these valves are not required to be Type C tested. The other containment isolation valves will be Type C tested.

General Test Methods

Isolation valves whose seats may be exposed to the containment atmosphere during a LOCA will be pneumatically tested with air or nitrogen. Valves in lines that would be filled with liquid for at least 30 days during the course of a LOCA will be tested with that liquid. Isolation valves will be closed by normal means without preliminary exercising or adjustments. Piping within the test boundary will be drained as necessary to assure that a water seal does not produce inaccurate results. The pressure decay method or flow meter makeup method of leakage rate measurement will be used.

Test Pressures

The test pressure will be P_a for pneumatic tests and 1.1 P_a for liquid tests.

Acceptance Criteria

Type C test results will be combined with Type B results.

Scheduling of Tests

Type C tests will be performed periodically in accordance with the containment leakage rate testing program to be developed by each COL applicant. The staff finds that the leakage rate testing provisions proposed for Type A, Type B, and Type C testing are acceptable because they are in accordance with the requirements of Appendix J to 10 CFR Part 50 and the appropriate guidance documents cited above.

6.2.6.4 Technical Specifications

In DSER Section 6.2.6.4, "Technical Specifications," the staff found one exception to staff guidance concerning the format and content of TSs for containment leakage rate testing. The numerical value of P_a should be stated in the TS, but was not. This is inconsistent with the requirements of Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," to 10 CFR Part 50. Option B of Appendix J to 10 CFR Part 50 requires the numerical value of P_a to be specified in the TS.[1]

TS 5.5.8, "Containment Leakage Rate Testing Program," states, "The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is less than the design pressure of containment." In contrast, the Westinghouse Owners Group (WOG) Standard TSs state, "The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is [45 psig]." This apparent difference was designated as Open Item 6.2.6.4-1 in the DSER.

Westinghouse has subsequently changed the subject passage in TS 5.5.8 to state, "The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is [57.8] psig. The containment design pressure is 59 psig."

This change resolves the staff's concern and is consistent with the WOG Standard TSs and the requirements of Appendix J to 10 CFR Part 50. Therefore, Open Item 6.2.6.4-1 is closed.

6.2.6.5 Conclusions

On the basis of its review the staff concludes that the proposed AP1000 containment leakage rate testing program complies with the acceptance criteria of Section 6.2.6 of the SRP. Compliance with the SRP acceptance criteria provides adequate assurance that containment leaktight integrity can be verified before initial operation and periodically throughout its service life. Compliance with the criteria in Section 6.2.6 of the SRP, as described in this section, constitutes an acceptable basis for satisfying the containment leakage rate testing requirements of GDC 52, GDC 53, and GDC 54, and Appendix J to 10 CFR Part 50.

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[1]Appendix J allows any applicant or licensee to choose to conform to either Option A of Appendix J (Prescriptive Requirements), Option B (Performance-Based Requirements), or a specific combination of Options A and B. The plant TS must specify which choice the applicant or licensee has made. THE WOG STS contains three versions of this TS, to account for these possibilities. Two of the versions (Option B and Options A and B combined) specify the value of P_a, but the Option A version does not. This is because Option A does not require it; Option B does. The AP1000 DCD allows COL applicants to choose which option of Appendix J they want, but the staff considers it unlikely that an applicant will choose Option A alone. All operating plants currently have chosen either Option B or a combination of Options A and B, because of the cost savings to be realized by using Option B. The AP1000 TS proposes to follow the Option B model.

6.2.7 Fracture Prevention of Containment Pressure Boundary

GDC 1 requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function.

GDC 16 requires that reactor containment and associated systems shall be provided to establish an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

GDC 51, "Fracture Prevention of Containment Pressure Boundary," requires that the reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner, and (2) the probability of rapidly propagating fracture is minimized.

The staff reviewed the AP1000 DCD to ascertain whether containment pressure boundary materials meet the requirements of GDC 1, 16, and 51.

<u>Summary of Technical Information</u>

DCD Tier 2, Section 3.8.2, indicates that the AP1000 containment vessel will use SA738, Grade B, material. DCD Tier 2, Section 3.8.2, also states that the materials for the AP1000 containment vessel, including the equipment hatches, personnel locks, penetrations, attachments, and appurtenances will meet the requirements of Subsection NE-2000 of the ASME Code, Section III.

<u>Staff Evaluation</u>

SA738, Grade B, material is an ASME Code material that is appropriate for the intended containment vessel application. The staff finds acceptable the selection of SA-738, Grade B, material for the AP1000 containment vessel, and the design and construction in accordance with the requirements of ASME Code, Subsection NE-2000. However, the staff requested, in RAI 252.009, that the following requirements be provided to supplement the requirements of specification SA-738 and that these requirements be included in the AP1000 DCD:

- Supplementary Requirement S1.7, "Vacuum Carbon-Deoxidized Steel," of Material Specification SA-738 applies to this material

- Supplementary Requirement S20, "Maximum Carbon Equivalent for Weldability," of Material Specification SA-738 also applies to this material

These two requirements are needed to ensure adequate material properties and weldability of the containment vessel material. ASME Code, Section III, exempts SA-738, Grade B, material up to 4.44 cm (1.75 in.) of thickness from postweld stress relief heat treatment. The AP1000 containment vessel is 4.44 cm (1.75 in.) thick. Because the containment vessel material thickness is 4.44 cm (1.75 in.) thick, the welds will not be stress relieved and, therefore, higher residual stresses will be present in the welds. Also, the material will likely be procured in the quenched and tempered condition. Welding will reduce the impact properties of the material in the heat affected zone. Requiring vacuum-degassed steel will ensure adequate material properties because nonmetallic inclusions, such as oxides and silicates, will be minimized as a result of the vacuum degassing of the steel. The S20 carbon-equivalent weldability check will ensure that the steel is readily weldable.

Westinghouse responded to RAI 252.009 by revising the DCD to require that supplementary requirements S1.7 and S20 be specified for the AP1000 containment vessel material.

<u>Conclusions</u>

Based on the review of the information included in the AP1000 DCD and the fact that the applicant will meet the requirements of Subsection NE-2000 of the ASME Code, Section III, the staff finds that the fracture toughness of the materials of the reactor containment pressure boundary meet the fracture toughness requirements invoked for ASME Code Section III, Subsection NE, Class MC materials. This satisfies the requirements of GDC 51 for fracture prevention of the containment pressure boundary. Meeting the requirements of ASME Code, Section III, also satisfies the requirements of GDC 1 for quality standards and records and GDC 16 for containment design.

The staff, therefore, concludes that reasonable assurance will be provided that the materials of the reactor containment pressure boundary, under operating, maintenance, testing, and postulated accident conditions, will not undergo brittle fracture and that the probability of rapidly propagating fracture will be minimized, so that the requirements of GDC 1, 16, and 51 will be met.

6.2.8 In-Containment Refueling Water Storage Tank Hydrodynamic Loads

DCD Tier 2, Section 6.3.2.2.3, Table 6.3-2, and Figure 6.3-4 describe the IRWST as a stainless steel-lined tank located underneath the operating deck inside the containment. The IRWST is AP1000 Equipment Class C and is designed to meet seismic Category I requirements. The tank is constructed as an integral part of the containment internal structures and is isolated from the steel containment vessel. The tank contains a minimum water volume of 2093 m^3 (73,900 ft^3).

The AP1000 design utilizes an ADS to depressurize the RCS so that long-term gravity cooling of the RCS may be established following various postulated plant events. The ADS system is composed of four distinct stages for blowdown of the RCS; the first, second, and third stages discharge into the IRWST. These discharges enter the IRWST via two submerged spargers so that the steam/water discharge from the RCS is quenched in the IRWST water. Discharging a hot pressurized steam/water mixture into a pool of relatively cool water is an efficient method for quenching the hot pressurized mixture. However, it also produces significant oscillatory hydrodynamic loads on the IRWST structure. These loads must be incorporated into the design of the IRWST structure.

To prevent imposing excessive dynamic loads on the tank structures, the spargers provide a controlled distribution of steamflow.

For the AP600, the hydrodynamic loads were determined based on tests conducted at the valve and pressure operating related experiments (VAPORE) test facility. The tests were divided into Phase A and Phase B. WCAP-13891, Revision 0, describes the Phase A tests; WCAP-14324 describes the Phase B tests. Phase A tests simulated ADS operation through the submerged sparger to evaluate the hydraulic performance of the sparger under various steamflow rates and to measure pressure pulses resulting from the discharge of steam into the quench tank simulating the IRWST. These results were used to define the dynamic forcing functions generated by the condensation of the steam. This information was used, in turn, to determine the dynamic loads imposed on the actual AP600 IRWST during sparger operation. Phase B tests developed functional requirements and assessed the performance of the ADS valves.

In response to RAI 220.001, Westinghouse stated that the AP600 ADS hydraulic tests were used to define loads on the AP1000 IRWST. Two tests were selected as representative of the sparger discharge pressures. One test simulated the pressure-time history corresponding to the ADS operating beyond 400 seconds after ADS initiation, when the RCS pressure is reduced and significant two-phase flow is discharged through the spargers. The other test simulated a pressure-time history representing the inadvertent opening of the second or third stage of the ADS at full pressure. The latter test is characterized by pure steamflow.

The response of the AP1000 IRWST to these time-history forcing functions is discussed in reference to RAI 220.009.

Westinghouse states that the time histories from these two tests are applicable to the AP1000 because the ADS valves and the ADS piping and spargers are identical for both the AP600 and the AP1000 designs. The valve opening times, flow areas, and fluid conditions are also the same. The ADS flow rate for the two-phase flow test is bounded by the value used for the AP1000 design. For the single-phase flow test, the important time is the initial time; the fluid conditions are similar.

Because the designs are identical and the fluid conditions for the tests used to determine the loads are bounding in one case and similar in the other, the staff finds the hydrodynamic loads on the IRWST for the AP1000 to be acceptable.

6.3 Passive Core Cooling System

The PXS is a safety-related system designed to perform the following safety-related functions:

- emergency core decay heat removal
- RCS emergency makeup and boration
- safety injection

- containment sump pH control

The PXS is located inside the containment, and consists of the following major subsystems and associated components:

- an IRWST
- a PRHR HX
- two CMTs
- an ADS
- two accumulators
- pH adjustment baskets
- associated piping, valves, instrumentation, and other related equipment

These PXS subsystems or components require only a one-time alignment of valves upon actuation. Once the initial actuation alignment is made, they rely solely on natural forces, such as gravity and stored energy, to operate. The use of active equipment or supporting systems, such as pumps, ac power sources, component cooling water, or service water, is not required.

DCD Tier 2, Figures 6.3-3 and 6.3-4 provide a general sketch of the PXS configuration. The IRWST is a large tank located above the elevation of the RCS loops that contains more than 2,234 m^3 (78,900 ft^3) of borated water. It is the source of low-pressure safety injection by gravity and the heat sink for the PRHR HX, which is submerged within it. The PRHR HX is connected to the RCS through an inlet line from one RCS hot-leg and an outlet line to the associated SG cold-leg plenum (RCP suction). The PRHR HX removes core decay heat by natural circulation. The CMTs, which are filled with borated water during normal operation, are located at an elevation above the RCS loops, and are connected to the RCS by pressure balance lines from the cold-legs, which maintain the CMTs at the RCS pressure. The outlet line from the bottom of each CMT provides an injection path to the DVI lines into the reactor. The ADS consists of four different stages of valves. The first three stages are connected to the top of the pressurizer and discharge through a sparger into the IRWST. The fourth-stage valves connect to the top of the RCS hot-legs and vent directly into the SG compartment. The ADS valves are actuated sequentially to depressurize the RCS to allow for gravity injection from the IRWST. The accumulators are filled with borated water that is pressurized with nitrogen gas and will inject, via the DVI lines, into the RCS when the RCS pressure falls below the accumulator pressure. The containment sump water pH control uses pH adjustment baskets containing granulated TSP, which dissolves when the containment sump water floodup reaches the baskets, to maintain the required recirculation sump pH during severe accident conditions.

The PXS is designed to mitigate design-basis events that involve a decrease in the RCS inventory such as a LOCA, or an increase or decrease in heat removal by the secondary system. For those non-LOCA events that result in an increase or decrease in heat removal by the secondary system, the PRHR HX and CMT are actuated by the protection and safety monitoring system (PMS) to remove core decay heat and provide makeup and boration for reactor coolant shrinkage. For events that reduce RCS inventory, the CMTs are actuated by the PMS to deliver borated water to the RCS via the DVI nozzles. As the CMTs drain down, the ADS valves are sequentially actuated to depressurize the RCS and establish the low-pressure conditions that allow injection from the accumulators, the IRWST, and the containment recirculation sump.

The staff's review of the PXS uses SRP Section 6.3 as guidance. Because the AP1000 PXS is quite different from the ECCS of the existing PWR designs, some SRP guidelines do not apply.

The staff reviewed the PXS for conformance with the following requirements:

- GDC 2, "Design Basis for Protection Against Natural Phenomena," as it relates to the seismic design of the SSCs the failure of which could cause an unacceptable reduction in the capability of the ECCS to perform its safety function
- GDC 4, as it relates to the dynamic effects associated with flow instabilities and loads
- GDC 5, "Sharing of Structures, Systems, and Components," as it relates to SSCs that are important to safety being prohibited from being shared among nuclear power units unless it can be demonstrated that sharing will not impair their ability to perform their safety function
- GDC 17, "Electric Power Systems," as it relates to the onsite and offsite electric power systems to permit functioning of the ECCS to provide sufficient capacity to ensure that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded and that the core is cooled during anticipated operational occurrences and accident conditions
- GDC 27, "Combined Reactivity Control Systems Capability," as it relates to the system being designed with the capability to ensure that, under postulated accident conditions and with appropriate margin for stuck rods, the capability to cool the core is maintained
- GDC 34, "Residual Heat Removal," as it relates to the ability of the residual heat removal system to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded
- GDC 35, "Emergency Core Cooling," GDC 36, "Inspection of Emergency Core Cooling System," and GDC 37, "Testing of Emergency Core Cooling System," as they relate to the ability of the ECCS to provide an abundance of core cooling to transfer heat from the core at a rate so that fuel and clad damage will not interfere with continued effective core cooling, to permit appropriate periodic inspection of important components, and to permit appropriate periodic pressure and functional testing
- 10 CFR 50.46 and Appendix K to 10 CFR Part 50, as they relate to analysis of the ECCS performance to ensure that it is accomplished in accordance with an acceptable evaluation model.

6.3.1 Design Bases

In DCD Tier 2, Section 6.3.1, Westinghouse describes the AP1000 PXS design bases. The PXS is designed to perform its safety-related functions on the basis of the following considerations:

- It has component redundancy to perform safety-related functions for postulated design-basis events.
- Components are designed and fabricated according to industry-standard quality groups commensurate with their intended safety-related functions following events such as fire, internal missiles, or pipe breaks.
- Components are tested and inspected at appropriate intervals, as defined by ASME Code, Section XI, and by TSs.
- Components are protected from the effects of external events, such as earthquakes, tornados, and floods.
- Components are sufficiently reliable, considering redundancy and diversity, to support the plant core melt frequency and significant release frequency goals.

The following sections describe the safety-related functional performance criteria of the PXS.

6.3.1.1 Emergency Core Decay Heat Removal

For non-LOCA events in which a loss of core decay heat removal capability via the SGs occurs, the PRHR HX is designed to automatically actuate to (1) remove core decay heat to prevent water relief through the pressurizer safety valves, (2) cool the RCS to 215.6 °C (420 °F) within 36 hours, with or without RCPs operating, (3) continue decay heat removal operation for an indefinite time in a closed-loop mode of operation in conjunction with the PCS, and (4) sufficiently reduce RCS temperature and pressure during an SG tube rupture (SGTR) event to terminate breakflow, without overfilling the SG.

6.3.1.2 RCS Emergency Makeup and Boration

For non-LOCA events that result in an inadvertent cooldown of the RCS, such as a steamline break, the PXS will automatically provide sufficient borated water to make up for reactor coolant shrinkage, counteract the reactivity increase caused by the system cooldown, allow for decay heat removal, prevent actuation of the ADS, and eventually bring the RCS to a subcritical condition.

6.3.1.3 Safety Injection

The PXS provides sufficient water to the RCS to mitigate the effects of a LOCA. In the event of a large-break LOCA, up to and including a cold-leg guillotine break, the PXS rapidly refills the reactor vessel, refloods the core, and continuously removes the core decay heat so that the performance criteria for ECCSs are satisfied.

The ADS valves are designed so that the PXS will satisfy the small-break LOCA performance requirements and provide effective long-term core cooling.

6.3.1.4 Safe Shutdown

Establishing a safe-shutdown condition requires maintenance of the reactor in a subcritical condition and adequate cooling to remove residual heat. One of the functional requirements for the PXS is that the plant be brought to a stable condition using the PRHR HX for non-LOCA events. Because of the functional limitations of the safety-related PRHR HX in passive plant designs, the Commission, in an SRM issued June 30, 1994, approved the position proposed in SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs." This position accepts 215.6 °C (420 °F) or below, rather than the cold shutdown specified in RG 1.139, "Guidance for Residual Heat Removal," as the safe stable condition that the passive decay heat removal system must be capable of achieving and maintaining following non-LOCA events. The PXS establishes safe shutdown by providing the necessary reactivity control to maintain the core in a subcritical condition, and by providing residual heat removal capability to maintain adequate core cooling. DCD Tier 2, Section 7.4, discusses the systems required for safe shutdown.

For non-LOCA events, the PRHR HX, in conjunction with the PCS, has the capability to bring the plant to a stable safe-shutdown condition, cooling the RCS to about 215.6 °C (420 °F) in 36 hours, with or without the RCPs operating.

The CMTs automatically provide emergency coolant makeup and boration to the RCS as the temperature decreases and pressurizer level decreases, opening the CMT injection valves upon a low-pressurizer level. The PXS can maintain stable plant conditions for an extended period of time in this mode of operation, depending on the reactor coolant leakage, without ADS actuation. For example, with reactor coolant leakage at the TS limit of 38 L/min (10 gpm), stable plant conditions can be maintained for at least 10 hours.

The ADS automatically actuates when the liquid volume in the CMTs decreases below the ADS actuation setpoints. The ADS valves are powered by the Class 1E dc batteries which provide power for at least 24 hours. A timer, which measures the time that ac power sources are unavailable and, therefore, the time the Class 1E batteries are being discharged, is used to automatically actuate the ADS if offsite and onsite ac power sources are lost for 24 hours. Therefore, for LOCAs or other postulated events in which ac power sources are lost, or when the CMT levels are sufficiently low, the ADS is automatically actuated. This results in injection from the accumulators, and subsequently from the IRWST, once the RCS is nearly depressurized. For these conditions, the RCS depressurizes to saturated conditions at about 121.1 °C (250 °F) within 24 hours. The PXS can maintain the plant in this safe-shutdown condition indefinitely.

6.3.1.5 Containment Sump pH Control

The pH adjustment baskets of the PXS are capable of maintaining the postaccident pH conditions in the recirculation water within a range of 7.0 to 9.5 after containment floodup to enhance radionuclide retention in the containment sump and prevent SCC of containment components during long-term containment floodup.

6.3.2 System Design

The AP1000 PXS is a seismic Category 1, safety-related system located inside the containment. Therefore, the PXS is designed for a single NPP, and is not shared between units, as required by GDC 5. GDC 17 requires that an onsite and offsite electric power system be provided to permit functioning of SSCs important to safety. The PXS relies on natural forces to perform its safety functions. It does not rely on any active system, except for one-time alignment of dc-powered valves upon actuation. Therefore, no safety-related onsite or offsite ac electric power is needed for PXS functions. The PXS is designed to provide adequate core cooling for design-basis events. Redundant onsite safety-related Class 1E dc and UPS system power sources are provided to ensure that the system safety functions can be accomplished under conditions when all ac power is lost, and assuming a single failure has occurred coincident with an event.

The PXS design comprises the six major subsystems or components that function together in various different combinations to perform safety-related functions. A description of the six major subsystems and components follows. DCD Tier 2, Figures 6.3-1 and 6.3-2 depict the piping and instrumentation drawings of the PXS. DCD Tier 2, Table 6.3-2, contains a summary of equipment parameters for the major components.

6.3.2.1 Core Makeup Tanks

The CMTs provide RCS makeup and boration during non-LOCA events when the normal makeup system is unavailable or insufficient. For LOCA events, the CMTs provide high-pressure safety injection to the RCS.

The two CMTs are vertical, cylindrical tanks with hemispherical upper and lower heads located inside containment on the 32.6 m (107-ft) floor elevation, slightly above the RCS loops (the bottom inside surface of each CMT is at least 2.3 m (7.5 ft) above the DVI nozzle centerline). Each CMT, having a volume of 70.8 m^3 (2500 ft^3), is connected to the RCS through an inlet pressure balance line connecting to a cold-leg and a discharge line connected to a DVI line. Each CMT has an inlet diffuser, which is designed to reduce steam velocities entering the CMT during relatively large-size, small-break LOCAs, thereby minimizing potential water hammer. The CMTs are made of carbon steel, clad on the internal surfaces with stainless steel.

During normal operation, the CMTs are completely filled with cold, borated water of about 3400 ppm, and are maintained at the RCS pressure by the pressure balance line, which prevents water hammer upon initiation of the CMT injection. The inlet pressure balance line contains a normally open MOV, and is sized to supply sufficient steam to allow CMT injection for LOCAs, where the cold-leg becomes voided and higher CMT injection flows are required. The pressure balance line also includes a high point vent line, which has two manual isolation valves in series and discharges to the reactor coolant drain tank. The operator can open the isolation valves to remove and prevent the accumulation of noncondensible gases that could interfere with CMT operation. The discharge line has two parallel, normally closed, air-operated isolation valves that will open upon a loss of air pressure or electric power, or on control signal actuation, to begin CMT injection. Downstream of the AOVs, the outlet lines combine into one line, which contains two tilt-disc check valves in series to prevent backflow from the DVI line. The discharge line from each CMT contains a flow-tuning orifice to provide for field adjustment of the injection line resistance to establish the required flow rates for the associated plant conditions assumed in the CMT design. The flow-tuning orifice will be adjusted as part of the preoperational test program.

The CMT is actuated by the opening of the two parallel isolation valves in the discharge lines. There are two operating processes for the CMTs, water recirculation and steam-compensated injection. During water recirculation, hot water from the cold-leg enters the CMT, and the cold water in the tank is discharged to the RCS. This results in RCS boration and a net increase in the RCS mass. During the steam-compensated injection, steam is supplied through the cold-leg balance line to the CMT to displace the water that is injected into the RCS.

DCD Tier 2, Section 7.3.1.2.3 and Table 7.3-1 describe the actuation signals and logic, as well as the permissives and interlocks, to align the CMT for injection; Table 3.3.2-1 of the AP1000 TS specifies the actuation setpoints. DCD Tier 2, Table 15.0-4b, provides the discharge valve opening delay times used in the safety analyses.

6.3.2.2 Accumulators

The two accumulators are spherical tanks located on the containment floor just below the CMTs. The accumulators, each having a volume of 56.63 m^3 (2000 ft^3), are filled with borated water at a concentration of about 2600 ppm and pressurized with nitrogen gas to a pressure between 4.49 and 5.4 MPa (651 and 783 psia). Each accumulator is connected to one of the DVI lines. Each injection line contains an MOV, a flow-tuning orifice, and two swing-disc check valves in series. The MOV is normally open with power removed and locked out to prevent inadvertent isolation. The flow-tuning orifice provides for field adjustment of the injection line resistance. During normal operation, the accumulator is isolated from the RCS by the check valves. The accumulators have gas relief valves to protect them from overpressurization caused by leakage from the RCS. The system also includes the capability to remotely vent gas from the accumulator, if required. During a LOCA, when the RCS pressure falls below the accumulator pressure, the check valves open and the borated water is forced into the RCS by the gas pressure. The AP1000 accumulator check-valve application is identical to that for current plants.

6.3.2.3 In-Containment Refueling Water Storage Tank

The IRWST is a large, stainless-steel lined tank containing 2,234 m^3 (78,900 ft^3) of borated water with a boron concentration of about 2,600 ppm. The IRWST is a safety injection source, and also serves as the heat sink for the PRHR HX, which is submerged within it. The IRWST is connected to the RCS through both DVI lines. The IRWST is AP1000 Class C equipment, designed to meet seismic Category I requirements, and is constructed as an integral part of the containment internal structures. Its bottom is above the RCS loop elevation (the bottom inside surface is at least 1.04 m (3.4 ft) above the DVI nozzle centerline) so that the borated refueling water can drain and inject by gravity into the RCS after the RCS is depressurized. Each injection line from the IRWST contains an MOV, which is normally open with power removed and locked out. The injection line contains two parallel lines, each with a check valve and a squib valve in series. RCS injection from the IRWST is possible only after the RCS has been depressurized by the ADS or a LOCA. Squib valves in the IRWST injection lines open automatically on a fourth-stage ADS initiation signal. Check valves open when the reactor pressure decreases below the IRWST injection head.

After the accumulators, CMTs, and IRWST inject, the containment is flooded to a level sufficient to provide recirculation flow through the gravity injection lines back into the RCS. There are two containment recirculation lines from the containment sump, each connecting to an IRWST injection line. Each recirculation line contains two parallel lines, one having a normally open MOV and a squib valve in series, and the other having a check valve and a squib valve in series. When the IRWST level decreases to a low level, the recirculation line squib valves automatically open to provide redundant flowpaths from the containment to the reactor.

DCD Tier 2, Section 7.3.1.2.2 and Table 7.3-1 describe the actuation signals and logic, as well as the permissives and interlocks, to align the IRWST injection and containment recirculation; Table 3.3.2-1 of the AP1000 TS specifies the actuation setpoints.

The IRWST and the containment recirculation sump are each provided with two separate screens to prevent debris from entering the reactor and blocking core cooling passages during a LOCA. These screens are oriented vertically, and located at the bottom of the opposite ends of the IRWST and the containment sump along the walls about 0.6 m (2 ft) above the floor. They are designed to comply with RG 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident." The IRWST is lined with stainless steel and does not contain material either in the tank or the recirculation path that could plug the outlet screens. The TS require visual inspections of the screens during every refueling outage to ensure they are not restricted by the debris. DCD Tier 2, Section 6.3.2.2.7, discusses the design of the IRWST and recirculation screens, as well as the design criteria. Section 6.2.1.8 of this report discusses the staff's evaluation of the IRWST and recirculation screens.

6.3.2.4 pH Adjustment Baskets

The PXS utilizes pH adjustment baskets to control the postaccident pH level in the containment sump within a range of 7.0 to 9.5. The baskets, which contain at least 12,518 kg (27,540 lbs) of granulated TSP, have a mesh front and are located below the minimum postaccident flood-up level so that chemical addition is initiated passively when the sump water reaches the baskets. The baskets are placed at least 0.3 m (1 ft) above the floor (the pH baskets are located below plant Elevation 32.7 m (107'-2") to reduce the chance that water spills in containment will dissolve the TSP.

The baskets are made of stainless steel with a mesh front that readily permits contact with water. Section 15.3 of this report evaluates the adequacy of the pH adjustment baskets.

6.3.2.5 Passive Residual Heat Removal Heat Exchanger

The PRHR HX consists of inlet and outlet channel heads connected by 689 vertical C-shaped tubes, 1.9 cm (0.75 in) in diameter. The tubes are supported and submerged inside the IRWST with the top of the tubes several feet below the IRWST water surface. The IRWST acts as a heat sink for the HX. The design heat transfer rate and flow are 2.11E+11 J/hr (2.00E+8 BTU/hr) and 2.28E+5 kg/hr (5.03E+5 lb/hr), respectively, as specified in DCD Tier 2, Table 6.3-2. The PRHR HX is connected to the RCS by an inlet line from one hot-leg (through a tee from one of the fourth-stage ADS lines) and an outlet line to the associated SG cold-leg plenum (RCP suction).

The PRHR HX performs emergency core decay heat removal for events not involving a loss of coolant. The HX is elevated above the RCS loops to induce natural circulation flow through the PRHR HX when the RCPs are not available. The PRHR HX inlet line contains a normally open MOV. This alignment maintains the HX full of reactor coolant at the RCS pressure. The outlet line contains two parallel, normally closed, AOVs that open upon loss of air pressure or on control signal actuation, and a normally open, manually operated valve in series. The two parallel valves in the discharge line ensure an available flowpath for the single-failure assumption of an inoperable valve in the safety analysis. DCD Tier 2, Table 15.0-4b, provides the discharge valve opening time delays assumed in the safety analyses. The water temperature in the HX is about the same as the water temperature in the IRWST, so that a thermal driving head is established and maintained during plant operation. The PRHR HX piping arrangement also allows for actuation of the HX with the RCPs operating, which provide forced flow in the same direction as the natural circulation. If the pumps are operating and subsequently trip, natural circulation continues to provide the driving force for HX flow. The PRHR HX flow and inlet and outlet temperatures are monitored by indicators and alarms. The operator can take action, as required, to meet the TS requirements or follow emergency operating procedures for control of the PRHR HX operation.

The PRHR HX has a high point vent, which is a vertical pipe stub on the top of the inlet piping high point that serves as a gas collection chamber. Level detectors indicate when the gases have collected in this area. The operator can open manual valves to locally vent these gases to the IRWST.

The PRHR HX, in conjunction with the PCS, can provide core cooling for an indefinite period of time. The operation of the PRHR HX results in the steaming of the IRWST water. Steam condensation occurs on the steel containment vessel, and the condensate returns to the IRWST through a safety-related gutter arrangement located at the operating deck level. The gutter normally drains to the containment sump, but will direct the gutter overflow to the IRWST when safety-related isolation valves in the gutter drainline shut at the initiation of the PRHR. Recovery of the condensate maintains the PRHR HX heat sink for an indefinite period of time.

DCD Tier 2, Section 7.3.1.2.7 and Table 7.3-1 describe the actuation signals and logic, as well as the permissives and interlocks, to align the PRHR HX for heat removal; Table 3.3.2-1 of the AP1000 TS specifies the actuation setpoints. DCD Tier 2, Table 15.0-4b, provides the discharge valve opening delay times used in the safety analyses.

6.3.2.6 Automatic Depressurization System

The ADS has a total of 20 valves divided into 2 identical groups, each consisting of 4 different stages of valves. Each of the first three stages has two normally closed, dc MOVs in series, one termed an isolation valve and the other a control or depressurization valve. The isolation valves are gate valves, and the control valves are globe valves. The fourth stage in each group has a common header connected directly to the top of an RCS hot-leg. The header branches into two lines, each containing a normally open motor-operated gate valve and a squib valve in series. The fourth-stage valves vent directly to the SG compartment. DCD Tier 2, Section 5.4.6.2, specifies that the first-stage ADS valves are motor-operated, 10-cm (4-in.) valves, the second- and third-stage valves are 20-cm (8-in.) valves, and the fourth-stage valves are 35.6-cm (14-in.) valves.

The first three stages in each group have a common inlet header connected to the top of the pressurizer. The outlets of each group of the first three stages are combined into a common discharge line to a sparger. The sparger has four branch arms inclined downward. The sparger midarms are submerged below the normal water level in the IRWST and are designed to distribute steam into the IRWST, thereby promoting more effective steam condensation. The installation of the spargers prevents undesirable and excessive dynamic loads on the IRWST. Each sparger is sized to discharge at a flow rate that supports the ADS performance to depressurize the RCS to allow adequate PXS injection. The common discharge line also has a vacuum breaker to help prevent water hammer following ADS operation by limiting the pressure reduction caused by steam condensation in the discharge line, and thus limiting the potential for liquid backflow from the IRWST.

The ADS valves are designed to automatically open when their actuation setpoints are reached, and remain open for the duration of an automatic depressurization event. The Stages 1, 2, and 3 ADS valves open sequentially. The isolation valves in each stage open first, followed by the control valves, which are designed to open relatively slowly, after a short time delay. DCD Tier 2, Section 7.3.1.2.4, discusses the ADS actuation logic and Table 7.3-1 summarizes this information. The first stage valves automatically actuate on the CMT Low-1 level signal; the second- and third-stage valves actuate subsequently with preset time delays between stages. The fourth-stage valve actuates upon the coincidence of a CMT Low-2 level and low RCS pressure, following a preset time delay after the third-stage depressurization valves are opened. The fourth-stage valves can also be opened upon the occurrence of coincidence loop 1 and loop 2 hot-leg levels below the Low-2 setpoint for a duration exceeding a time delay. This signal is automatically blocked when the pressurizer water level is above the P-12 setpoint to reduce the possibility of a spurious signal. DCD Tier 2, Table 15.6.5-10, provides a list of ADS parameters, including the CMT levels when the various ADS stage valves actuate, the actuation delay times, minimum valve flow areas, and valve opening times. The operators can also manually open the first-stage valves to a partially open position to perform a controlled RCS depressurization. The operator can also manually initiate the fourth-stage valves. The manual initiation signal is interlocked to prevent actuation until either the RCS pressure has decreased below a preset setpoint, or until the signals that control the opening sequence of the first three stages have been generated.

6.3.2.7 Low-Differential, Pressure Opening Check Valves

Passive core cooling systems contain several check valves designed to operate with low-differential pressures which could affect the passive system reliability. Section B, "Definition of Passive Failure," of SECY-94-084, describes a Commission-approved position (SRM issued June 30, 1994) to maintain current licensing practices for passive component failures in passive LWR designs. The position also redefines check valves (except for those whose proper function can be demonstrated and documented) in the passive safety systems as active components subject to single-failure consideration.

The AP1000 PXS has been specifically designed to treat check valve failures-to-reposition as active failures. It assumes that normally closed check valves fail to open and normally open check valves fail to close. Check valves that remain in the same position before and after an event are not considered active failures. Exceptions to this treatment in the PXS are made for the accumulator and CMT check valves. The treatment of the accumulator check valves is consistent with the treatment of these specific check valves in currently licensed plant designs because the accumulator pressure will eventually create a large pressure differential to force open the valves as the RCS pressure falls. The CMT check valve exception to active failure treatment is discussed below.

DCD Tier 2, Section 1.9.5.3.2, states that the AP1000 is designed with redundancy for the check valve applications in the CMT discharge lines, the IRWST gravity injection lines, and the containment isolation lines that use check valves. The redundancy and diversity in the design among these multiple safety-related flowpaths is sufficient to accommodate the single failure of a check valve to reposition as required to perform its safeguard function. The staff agreed with Westinghouse's position, and used this position to evaluate the appropriateness of the check valve arrangements in the PXS as described below.

Both the IRWST and the containment recirculation injection lines contain normally closed, simple swing check valves, which must change position to perform their safety functions. Therefore, these check valves are considered active components subject to the single-failure assumption. Each IRWST injection line contains two parallel paths, each having a check valve and a squib valve in series. The redundant parallel paths design assures operability of the IRWST injection with a single failure of a check valve. The containment recirculation injection line also contains two redundant parallel paths, one having a check valve and a squib valve in series, and the other having a normally open MOV and a squib valve in series.

Each CMT injection line contains two tilt-disc check valves in series to prevent backflow from the DVI line. However, these tilt-disc check valves are biased open during normal plant operation and do not have to change position to perform their safety function to open the CMT injection lines. Only a low probability exists that these check valves will not reopen within a few minutes after they have cycled closed during accumulator operation. Therefore, they are considered passive components, not subject to single-active-failure consideration for the opening function. However, a single-active-failure has been taken into account for the closing function of these check valves by providing two check valves in series.

Each accumulator injection line contains two normally closed, swing check valves in series to prevent the RCS backflow. However, these check valves are similar to the check valves used in current PWR applications and are in the closed position with a differential pressure of about 10.6 MPa (1550 psid) during normal operation. They are not subject to the degradation from flow operation or impact loads caused by sudden flow reversal and seating. During a LOCA, these check valves will be forced open by a large differential pressure created by the accumulator pressure as the RCS depressurizes. Therefore, as stated above, they are not subject to single-active-failure consideration.

The staff finds that the check valve arrangements in the PXS are designed with redundancy to accommodate the single active failure of a check valve to reposition as required to perform its safeguard function, and are therefore acceptable.

6.3.2.8 System Reliability

The AP1000 PXS is designed to satisfy a variety of requirements to ensure its availability and the reliability of its safety functions, including redundancy (e.g., for components, power supplies, actuation signals, and instrumentation), equipment testing to confirm operability, procurement of qualified components, and provisions for periodic maintenance. In addition, the design provides protection against single active and passive component failures; spurious failures; physical damage from fires, flooding, missiles, pipe whip, and accident loads; and environmental conditions, such as high-temperature steam and containment floodup. These requirements are specified in GDC 2, 4, 34, 35, 36, and 37.

To ensure system operability and allow for immediate corrective actions, the PXS equipment conditions are monitored with indications and/or alarms in the MCR to alert the operator of equipment conditions outside of the TS limits. The monitored parameters include the CMT level, temperature, and inlet line noncondensible gas volume; accumulator level and pressure; IRWST level and temperature; and PRHR HX inlet line noncondensible gas volume.

6.3.2.8.1 Redundancy and Single-Failure Consideration

The PXS system is designed with sufficient redundancy to withstand credible single active and passive failures. The AP1000 has been specifically designed to treat check valve failures-to-reposition as active failures. Check valves that remain in the same position before and after an event are not considered active failure. As discussed in Section 6.3.2.7 of this report, the accumulator check valve opening and the CMT check valve reopening are the two exceptions. Chapter 15 of the DBA analyses considers single active failures. In addition, for those valves that reposition to initiate safety-related system functions, the valve reposition times are less than the times assumed in the accident analyses.

A passive failure in a fluid system is a breach in the fluid pressure boundary or mechanical failure that adversely affects a flowpath. SECY-94-084 states the Commission-approved position that, consistent with current licensing practices, passive advanced light-water reactor (ALWR) designs need not assume passive component failures in addition to the initiating failure in the application of single-failure criterion to assure safety of the nuclear power plant. In addition, the staff only considers, on a long-term basis, passive component failures in fluid systems as potential accident initiators, in addition to initiating events. The AP1000 PXS can sustain a single passive failure during the long-term cooling phase and still retain an intact flowpath to the core to supply sufficient flow to keep the core covered and to remove decay heat. The PXS flowpaths are separated into redundant lines, either of which can provide minimum core cooling functions and return spill water from the floor of the containment back to the RCS. For the long-term PXS function, adequate core cooling capacity exists with one of the two redundant flowpaths.

The staff reviewed the piping diagrams of DCD Tier 2, Figures 6.3-1 through 6.3-4, to evaluate the functional reliability of the system in the event of single failures. The existence of the redundancy required by the single active failure is confirmed.

DCD Tier 2, Table 6.3-3, provides a summary of the failure mode and effect analysis of the PXS active components. To determine the effect on system operation, each of the valves in the PXS (including check valves, isolation valves, AOVs or MOVs, and squib valves) and the Class 1E dc and UPS system distribution switchgear division were examined for failure modes, as well as failure detection methods, for all design-basis events to determine the effect on system operation.

6.3.2.8.2 Valve-Opening Lag Times

For those valves that reposition to initiate safety-related system functions, the valve repositioning times are less than the times assumed in the accident analyses, as specified in DCD Tier 2, Table 15.0-4b. These lag times refer to the time after initiation of the safeguards actuation signal.

6.3.2.8.3 Potential Boron Precipitation

Boron precipitation in the reactor vessel is prevented by sufficient flow of PXS water through the core to limit the increase in boron concentration of the water remaining in the reactor vessel. Water, along with steam, leaves the core and exits the RCS through the fourth-stage ADS lines. The results of long-term cooling analysis of various breaks, presented in DCD Tier 2, Section 15.6.5.4C.4, indicate that venting of core steam and water ensures that there is adequate liquid flow through the core to cool it and to prevent boron precipitation. Section 15.2.7 of this report presents the staff's evaluation of this issue.

6.3.2.8.4 Testing and Inspection

The AP1000 PXS systems and components are designed to permit periodic inspection and testing of the operability of the system throughout the life of the plant, as required by GDC 36, "Inspection of Emergency Core Cooling System," and GDC 37. DCD Tier 2, Section 6.3.6, describes the inspection and testing requirements, including the preoperational and inservice inspection and testing. Preoperational inspections are performed to verify that important elevations associated with the PXS components are consistent with the accident analyses. DCD Tier 2, Section 14.2.9.1.3 describes the preoperational testing of the PXS. This testing includes valve inspection and testing, flow testing, and verification of heat removal capability.

Two basic types of inservice testing are performed on the PXS components, including periodic exercise testing of active components during power operation, and operability testing of specific PXS features during plant shutdown. To support inservice test performance, the PXS includes (1) remotely operated valves that can be exercised during routine plant maintenance, (2) level, pressure, flow, and valve position instrumentation to monitor required PXS equipment during plant operation and testing, and (3) permanently installed test lines and connections for operability testing. DCD Tier 2, Section 3.9.6.2, provides a description of the inservice testing of valves. DCD Tier 2, Tables 3.9-16 and 3.9-17, respectively, specify the valve inservice test requirements and system level operability test requirements.

6.3.2.8.5 Seismic and Equipment Classifications

The AP1000 PXS is a safety-related system, and all the subsystems are designed to meet seismic Category 1 requirements, as defined by RG 1.29. DCD Tier 2, Table 3.2-3, specifies the seismic category and the quality group classification of various system components. The PXS components are designed to meet the requirements of seismic Category 1 SSCs and withstand the effects of an SSE and remain functional. Because all the PXS subsystems rely on natural forces, such as gravity and stored energy, to perform their safety functions, they require no supporting systems, the failure of which could have an adverse effect on the PXS. No failure of a non-safety-related system could reduce the functioning of the PXS. Therefore, the PXS meets position C.2 of RG 1.29 and therefore fulfills GDC 2 requirements.

Portions of the PXS, such as the PRHR HX, CMT, and ADS, which are also part of the RCPB are designated AP1000 Class A components. For the portions of the PXS that are not part of the RCPB, RG 1.26 recommends that the ECCS systems be classified as Quality Group B. DCD Tier 2, Table 3.2-3, lists many PXS components as AP1000 Class C components. These Class C components include the following:

- the accumulators and injection line piping system up to the check valves
- the IRWST injection and containment recirculation piping up to the injection line check valves
- ADS Stages 1, 2, and 3 discharge spargers
- pH adjustment baskets

However, as discussed in Section 3.2.2 of this report, the staff determined that AP1000 Class C categorization for these portions of the PXS is acceptable. This finding is based on its evaluation of the design bases provided by Westinghouse, as well as the commitment stated in DCD Tier 2, Section 3.2.2.5 that for systems that provide ECC functions, full radiography, in accordance with the requirements of ASME Code, Section III, Subarticle ND-5222, will be conducted on the piping butt welds during construction.

6.3.2.8.6 Valves

Manual valves are generally used as maintenance isolation valves. When used for this function, they are under administrative controls. They are located so that no single valve can isolate redundant PXS equipment, or they are provided with position indication and alarms in the MCR to indicate mispositioning.

DCD Tier 2, Table 6.3-1, provides a list of the remotely actuated valves in the PXS subsystems, as well as their normal positions, actuated positions, and failed positions. These valves have their controls and valve position indication in the control room. The AP1000 TS requires that remotely operated isolation valves, such as the isolation valves on the PRHR inlet line, the CMT cold-leg balance lines, the accumulator and IRWST discharge lines, and the ADS fourth-stage MOVs, which are normally open and remain open during PXS operation, be verified fully open every 12 hours during normal plant operation. These isolation valves also have interlock features to ensure they are open for the PXS operation. DCD Tier 2, Section 7.6.2, "Availability of Engineered Safety Features," discusses the interlock features, and Section 7.6 of this report discusses the staff's evaluation of these features. These isolation valves do not receive safeguards actuation signals. They are normally manually controlled, but are also controlled by actuation control circuits, which have a function to direct the valve to open upon receipt of a "confirmatory open" signal in case the valves are closed. The use of confirmatory open signals to open these isolation valves, which are provided by the safeguards signals to actuate the respective PXS subsystem, provides a means to automatically override bypass features that are provided to allow these isolation valves to be closed for short periods of time. The accumulator and IRWST injection isolation valves have interlocks, and have their control power locked out during normal plant operation, in accordance with BTP Instrumentation and Control System Branch (ICSH)-18, to prevent their inadvertent operation.

The check valves in the IRWST injection line, the containment recirculation lines, the accumulator discharge lines, and the CMT injection lines have nonintrusive position indications and alarms in the MCR to alert the operators to valve mispositioning.

Explosively opening squib valves are used to isolate the IRWST injection line, the containment recirculation lines, and the ADS Stage 4 valves. These squib valves are used to provide zero leakage during normal operation, and to provide reliable opening during an accident. After they are open, they are not required to reclose. These valves are arranged in series with another valve. A valve open position sensor is provided for these valves.

6.3.2.8.7 Instrumentation

The AP1000 PXS design is provided with instrumentation for monitoring PXS components during normal plant operation and postaccident operation with indications and alarms in the MCR. The PRHR HX has pressure and inlet temperature indications to detect reactor coolant leakage into the PRHR HX. The PRHR HX also has two flow channels to monitor and control PRHR HX operation. Each accumulator has two pressure and two level channels to confirm that the pressure and level are within the bounds of the safety analysis assumptions. The IRWST has four temperature and four level channels to monitor the temperature and level. Each CMT has temperature indications in the inlet and outlet lines to determine if there is sufficient thermal gradient for system operation, and to detect RCS leakage into the CMT through the DVI line, respectively. Each CMT also has a level instrument, as discussed below, to be used for control of ADS actuation. Each DVI line has temperature indication to detect RCS leakage through the DVI line to the CMT, accumulator, or the IRWST. The containment has three level channels and four radiation channels. DCD Tier 2, Chapter 7, discusses the AP1000 instrumentation and controls, and Chapter 7 of this report discusses the staff's review of these components.

DCD Tier 2, Section 6.3.7.4.1, provides a design description of the CMT-level instrumentation using differential pressure instruments. DCD Tier 2, Figure 6.3-1, depicts the arrangement of the CMT differential pressure level instrument. Each CMT has 10 level channels. Two wide-range level channels, which are not qualified for postaccident monitoring, are used to confirm that the CMT is maintained at full water level during normal operation. Two sets of four narrow-range level channels, which are qualified for postaccident monitoring, are used for actuation of the ADS Stage 1 and Stage 4 valves. As discussed in Section 7.3 of this report, the staff found the CMT-level instrumentation to be acceptable.

6.3.2.8.8 Protection Provisions

The AP1000 PXS design incorporates specific design features that preclude water hammer and excessive dynamic loads, as required by GDC 4. These design features include the installation of the ADS spargers in the IRWST, the CMT inlet diffuser, sloping lines, and maintaining pressure in standby components. Various sections in the DCD describe measures taken to protect the system from damage that might result from various events. DCD Tier 2, Section 3.6, discusses protection against dynamic effects associated with piping rupture. DCD Tier 2, Section 3.9.3, discusses the load combinations, stress limits, and analytical methods for structural evaluation of the PXS for various plant conditions; DCD Tier 2, Section 3.9.2, discusses the requirements for dynamic testing and analysis. DCD Tier 2, Sections 3.7, 3.8, and 3.10 discuss seismic design. DCD Tier 2, Section 3.1.1, discusses environmental qualification of equipment. DCD Tier 2, Sections 3.5 and 9.5.1, respectively, discuss protection against missiles and from fire. The staff's evaluations of these DCD sections are discussed in the corresponding sections of this report.

6.3.3 Performance Evaluation

The AP1000 PXS is designed to mitigate design-basis events that involve a decrease in RCS inventory, an increase or decrease in heat removal by the secondary system, or events that can occur during shutdown operation.

6.3.3.1 Shutdown Events

During plant shutdown conditions, some of the PXS equipment is isolated to allow for maintenance of the system, and the RNS may not be available because it is not a safety-related system. As a result, gravity injection is automatically actuated when required to provide core cooling during shutdown conditions before refueling cavity floodup. In addition, the operator can manually actuate other PXS equipment, such as the PRHR HX, to provide core cooling during shutdown conditions if the equipment does not automatically actuate. Events that occur during shutdown conditions are characterized by slow plant responses and mild thermal-hydraulic transients. DCD Tier 2, Section 6.3.3.4, provides an evaluation of the PXS capability to mitigate the following four shutdown events:

(1) loss of startup feedwater during hot standby, cooldowns, and heatups
(2) loss of RNS cooling with the RCS pressure boundary intact
(3) loss of RNS cooling during midloop operation
(4) loss of RNS cooling during refueling

In DCD Tier 2, Section 19E.4, the applicant provided a more complete shutdown evaluation of applicable design-basis transients and accidents postulated to occur during shutdown operations. For each event category discussed in DCD Tier 2, Chapter 15, the applicant identified the limiting case and evaluated, for shutdown operations, the effects of plant control parameters, neutronic and thermal-hydraulic parameters, and ESFs on plant transient responses, such as departure from nucleate boiling ratio, peak RCS pressure, and peak cladding temperature. Section 19.3 of this report presents the staff's evaluation of shutdown operation. The staff concludes that the PXS with the shutdown configurations (to allow for maintenance of the system) is capable of coping with all events initiated during shutdown operation. Therefore, it is acceptable.

6.3.3.2 <u>Power Operation Events</u>

For non-LOCA events initiated during power operation, the PRHR HX is actuated by the PMS to remove core decay heat when any of the actuation conditions (e.g., SG Low wide-range level, SG low narrow-range level coincident with startup feedwater low flow, or CMT actuation) is reached. For LOCAs, the primary protection is provided by the CMTs and accumulators. When any of the PXS actuation conditions (e.g., low-pressurizer pressure or level, low-steamline pressure, high-containment pressure, or low SG level coincident with high RCS hot-leg temperature) is reached, the PMS will actuate the CMTs to deliver borated water to the RCS by means of the DVI nozzles. As the CMTs drain down, the ADS valves are sequentially actuated to depressurize and establish RCS pressure conditions that allow injection from the accumulators, and then from the IRWST and the containment recirculation sump. The accumulators deliver flow to the DVI line whenever RCS pressure drops below the tank static pressure. The IRWST provides gravity injection once the RCS pressure is reduced below the injection head from the IRWST. The PXS flow rates vary depending upon the type of event and its characteristic pressure transient. Therefore, an injection source is continuously available. In addition to initiating PXS operation, the PXS actuation conditions also initiate other automatic-action safeguards, including reactor trip, RCS pump trip, feedwater isolation, and containment isolation.

DCD Tier 2, Chapter 15, provides an evaluation of the design-basis events, and DCD Tier 2, Section 6.3.3, provides a summary of events that result in the actuation of the PXS to demonstrate functional performance capability of the PXS. An inadvertent opening of an SG relief or safety valve and a steam system pipe failure are among the non-LOCA events that result in an increase in heat removal by the secondary system. A loss of main feedwater and a feedwater system pipe failure are among the events that result in a decrease in heat removal by the secondary system. A single SGTR, LOCAs, and a complete severance of a single PRHR

HX tube are among the events that could result in a decrease in RCS inventory. DCD Tier 2, Sections 15.1, 15.2, and 15.6, respectively, analyzed these events. DCD Tier 2, Section 15.6, did not analyze a postulated double-ended rupture of one PRHR HX tube. The total area of a double-ended rupture of the PRHR HX is less than a 2.5-cm- (1-in.-) equivalent diameter break. With one tube ruptured, the PRHR HX remains essentially unaffected in terms of its heat removal capability. The PRHR tube rupture is nonlimiting and is covered by the effect of postulating a hot-leg or cold-leg break location considered in the break spectrum. DCD Tier 2, Section 15.6.5.4C, analyzes the post-LOCA, long-term cooling.

Chapter 15 of this report discusses the evaluation of the safety analyses of the design-basis events. In general, the design-basis analyses take credit for safety-related systems and components for mitigation of events. Consideration is given to operation of non-safety-related systems that could affect the event results. Section 15.1.2 of this report addresses the non-safety-related systems assumed in the design-basis analyses. A non-safety-related system or component is assumed to be operational when (1) its operation has an adverse effect that results in a more limiting transient, (2) a detectable and nonconsequential random, independent failure had to occur in order to disable the system, and (3) it is used as backup protection. Though GDC 17 regarding the requirements of onsite and offsite power supplies does not apply to the PXS, the effects of a loss of offsite power on the RCP trip and the results of transients and accidents are considered in the design-basis safety analysis. This complies with GDC 17. In addition, the analyses of the postulated accidents assume that the most reactive control rod stuck out of the core complies with GDC 27. The staff found the Chapter 15 design-basis analyses and the assumptions of the operation of non-safety-related systems and components, as well as other single-failure assumptions, to be acceptable.

The results of the Chapter 15 analyses demonstrate the appropriateness of the PXS performance for mitigation of the design-basis events. This complies with (1) GDC 34, in that the PRHR system is capable of transferring the decay heat and other residual heat from the core, such that the specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded, (2) GDC 35, in that the PXS provides abundant emergency core cooling capability following LOCAs so that fuel and cladding damage that could interfere with continued effective core cooling is prevented, and clad metal-water reaction is limited to a negligible amount, and (3) 10 CFR 50.46, in that the ECCS cooling performance is calculated in accordance with an acceptable evaluation model for the postulated LOCA break spectrum to demonstrate that the acceptance criteria specified in 10 CFR 50.46(b) are met.

The computer programs used for the analyses of these design-basis events are, respectively, LOFTRAN for the non-LOCA events, LOFTTR2 for the single SGTR event, NOTRUMP for small-break LOCAs, and WCOBRA/TRAC for large-break LOCAs and long-term cooling. Chapter 21 of this report discusses the review of these codes, as well as the test programs.

6.3.4 Post-72 Hour Actions

The AP1000 design relies on passive safety-related systems and equipment to automatically establish and maintain safe-shutdown conditions for the plant following design-basis events, assuming the most limiting single failure. These passive safety systems are designed with sufficient capability to maintain safe-shutdown conditions for 72 hours, without operator actions and without non-safety-related onsite or offsite power. Only one potential need exists for the containment inventory makeup to provide long-term core cooling because of containment leakage.

For the AP1000 PXS, the IRWST serves as the heat sink for the PRHR HX. During extended PRHR HX operation, steam from the IRWST is condensed by the PCS and the condensate returns to the IRWST by means of the safety-related gutter. This closed loop operation can continue indefinitely provided that no leakage through the containment occurs. For long-term core cooling, however, there is a potential need for operator action to provide containment inventory makeup, which is directly related to the leak rate from the containment. DCD Tier 2, Section 6.3.4, states that, with the maximum allowable containment leak rate, makeup to the containment is not needed for about 1 month. The AP1000 RNS design is equipped with a safety-related connection to align a temporary makeup source to containment. Therefore, the long-term cooling capability of the PXS is assured.

DCD Tier 2, Section 1.9.5.4, and WCAP-15985, Revision 2, "AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process," dated August 2003, describe the AP1000 design for the post-72 hour support actions required following an extended loss of these non-safety-related systems for the safety-related functions. The AP1000 design includes both onsite equipment and safety-related connections for use with transportable equipment and supplies to provide certain extended support actions. With regard to the PCS, the support actions use one of the two PCS recirculation pumps powered by an ancillary diesel generator or a portable, engine-driven pump that connect to a safety-related makeup connection that provides makeup water to the PCS water storage tank to maintain external containment cooling waterflow, and therefore provide the containment cooling and ultimate heat sink. Section 22.5.6 of this report describes the staff's evaluation of this post-72-hour support action. The staff concluded that since all equipment required for post-72 hour actions is onsite and consumable supplies are sufficient to last 7 days, the post-72 hour actions for the AP1000 are acceptable.

6.3.5 Limits on System Parameters

The plant TSs establish PXS operability requirements for reactor operation. TS 3.4.12 through 3.4.14, and 3.5.1 through 3.5.8 specify the limiting conditions for operation and SR of various PXS subsystems. In addition, planned maintenance on the PXS equipment is accomplished during refueling operations when the core temperatures and decay heat levels are low, and the IRWST water is in the refueling cavity. The TSs also provide the principal system parameters, the number of components that may be out of operation during testing, and the allowable time for operation in a degraded status. Chapter 16 of this report addresses the staff's evaluation of the TSs.

6.3.6 Conclusions

The staff reviewed DCD Tier 2, Section 6.3, and other relevant material regarding the AP1000 PXS design, including piping and instrumentation diagrams, failure modes and effects analyses, and the design specifications for essential components. The staff reviewed the AP1000 design bases and design criteria for the PXS, as well as the manner in which the design conforms to these criteria and bases. The staff concludes that the AP1000 PXS design meets the guidelines of SRP Section 6.3 and the requirements of the following GDC:

- GDC 2—The PXS is designed to meet the seismic Category 1 requirements and remain functional following an SSE.

- GDC 4—The PXS design incorporates features that preclude water hammer and excessive dynamic loads.

- GDC 5—The PXS is designed for a single NPP, and is not shared between units.

- GDC 17—The PXS performs its functions without relying on onsite or offsite ac power. The effects of loss of offsite power on the RCP trip and the results of the design-basis events are considered in the safety analyses which demonstrate the ability of the AP1000 to meet the acceptance criteria.

- GDC 27, 34, and 35—Safety analyses of the design-basis transients and accidents were performed with the assumption of the most reactive control rod stuck out of the core, and the results demonstrate that the PXS provides sufficient capability to remove residual heat and provide abundant core cooling so that (1) the specified acceptable fuel design limits and the design conditions of the RCS pressure boundary are not exceeded, and (2) the acceptance criteria specified in 10 CFR 50.46 for LOCAs are met.

- GDC 36 and 37—The PXS systems and components are designed to permit periodic inspection and testing of the operability of the system throughout the life of the plant.

The AP1000 design includes preoperational testing for the PXS, as discussed in DCD Tier 2, Section 14.2.9.1.3. In addition, DCD Tier 1 Information Section 2.2.3, "Passive Core Cooling System," Table 2.2.3-4, "Inspections, Tests, Analyses, and Acceptance Criteria," specifies (1) the design commitments of the PXS, (2) the inspections, tests, or analyses to be performed by the COL applicants, and (3) the acceptance criteria to ensure that the PXS is built by the COL applicants as designed. Therefore, the staff finds the AP1000 PXS design acceptable.

6.4 Control Room Habitability Systems

The staff reviewed the control room habitability systems in accordance with NUREG-0800, "Standard Review Plan," Section 6.4, "Control Room Habitability System." Conformance with the acceptance criteria of the SRP forms the basis for concluding that the control room habitability systems satisfy the following requirements:

- GDC 4, which states that structures, systems, and components important to safety shall be designed to accommodate the effects of and being compatible with the environmental conditions for normal operation, maintenance, testing, and postulated accidents

- GDC 5, regarding shared systems and components important to safety

- GDC 19, regarding providing a control room from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions

- TMI-related requirement 10 CFR 50.34(f)(2)(xxviii), regarding the evaluation of potential pathways for radioactivity and radiation that may lead to control room habitability problems

- TMI Action Plan Item III.D.3.4 (NUREG-0737), regarding protection against the effects of release of toxic substances, either on or off the site

Throughout this evaluation, reference is made to GDC 19 as applied to the AP1000 design. The staff used a dose criterion of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for evaluating the control room radiological consequences resulting from DBAs, pursuant to GDC 19 of Appendix A to CFR Part 50.

In DCD Tier 2, Section 3.1.1, Westinghouse states that the AP1000 design is a single-unit plant; if more than one unit is built on the same site, none of the safety-related systems will be shared. Thus, independence of all safety-related systems and their support systems will be maintained among the individual plants. The staff determined that the design described in the DCD does not share SSCs with other nuclear power units. Therefore, the air conditioning, HVAC systems meet the requirements of GDC 5.

During normal and postulated accident conditions, the habitability systems will provide the following:

- a controlled environment for personnel comfort and equipment operability

- radiation shielding against releases of airborne radioactive materials outside the control building

- protection against releases of airborne radioactive materials and toxic gases surrounding the control building

- protection against the effects of high-energy line ruptures in adjacent plant areas

- fire protection to ensure that the control room is manned continuously

In DCD Tier 2, Section 15.6.5.3.5, Westinghouse described the MCR dose model for calculating the radiation exposure of control room personnel for accident conditions.

The following systems provide the control room habitability functions for the plant:

- nuclear island nonradioactive ventilation system (VBS)
- main control room emergency habitability system (VES)
- radiation monitoring system (RMS)
- fire protection system (FPS)

- plant lighting system (ELS)

Section 9.5.1 of this report evaluates the use of noncombustible construction and heat and flame resistant materials throughout the plant to reduce the likelihood of fire and consequential impact on the atmosphere in the MCR envelope (MCRE). Manual hose stations outside the MCRE and portable fire extinguishers are provided to fight an MCR fire.

The RMS provides radiation monitoring and the ELS provides emergency lighting for the MCRE. The VBS provides normal and abnormal HVAC services to the MCR, technical support center (TSC), instrumentation and control rooms, dc equipment rooms, battery rooms, and the VBS equipment room, as long as an ac source of power is available. The VES is designed to provide emergency ventilation and pressurization for the MCRE when a source of ac power is not available to operate the VBS, or if radiation levels in the MCR supply air duct reach the high-high level. Section 12.3. of this report discusses radiation shielding corresponding to the design-basis LOCA. Section 15.3 of this report provides a description of design-basis LOCA source terms and an evaluation of control room operator doses. The VES is not required during normal operating conditions and is automatically initiated following a high-high particulate or iodine radioactivity signal in the MCR supply air duct, or if the VBS is inoperable (i.e., loss of ac power signals). The VES, as part of the habitability systems, is addressed in this section of this report. The VBS, FPS, ELS, and RMS are addressed in Sections 9.4.1, 9.5.1, 9.5.3, and 11.5 of this report, respectively.

The control habitability systems are capable of maintaining the MCRE environment suitable for control room operators for the duration of a postulated DBA to meet the requirements of GDC 19, as discussed in this section and in Section 15.3 of this report. Chapter 20 of this report discusses the AP1000 design's conformance with the requirements of Generic Issue B-66, "Control Room Infiltration Measurements," and TMI Action Item III.D.3.4, "Control Room Habitability."

As described in Section 9.4.1 of this report, the VBS includes redundant non-safety-related supplemental air filtration units. During abnormal operation, when high gaseous radioactivity is detected in the MCR supply air duct, and the VBS' MCR/TSC HVAC subsystem is operable, both supplemental air filtration units automatically start to pressurize the MCR/TSC areas to at least 3.2 mm (0.125 in.) water gauge using filtered makeup. Subsequently, one of the supplemental filtration units is manually shutdown. The normal outside air makeup duct and the MCR and TSC toilet exhaust duct isolation valves automatically close and the smoke/purge isolation dampers close, if open. The subsystem air handling unit continues to provide cooling in the recirculation mode to maintain the MCR/TSC areas within their design temperature. This maintains the MCRE passive heat sink below its initial ambient air design temperature in the event VES actuation is required. The supplemental filtration unit provides pressurization for the combined volume of the MCR and TSC. A portion of the recirculated air from the MCR and TSC is also filtered for clean up of airborne radioactivity.

During abnormal operation, if ac power is unavailable for more than a short period, or high-high particulate or iodine radioactivity is detected in the MCR supply air duct, which could lead to exceeding GDC 19 dose limits, the plant's safety monitoring system automatically isolates the MCRE from the normal MCR/TSC HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves. The VES safety-related supply isolation valve in each train opens automatically to protect the MCRE occupants from a potential radiation release.

DCD Tier 2, Figures 6.4-1, 1.2-8, and 12.3-1 depict the MCRE. DCD Tier 2, Figures 1.2-25 through 1.2-31, illustrate the areas adjacent to the MCRE. DCD Tier 2, Table 3.2-3, indicates that the VES is located in the auxiliary building, which is a missile-protected seismic Category 1 building. The MCR pressure boundary is located on Elevation 35.81 m (117'-6") in the auxiliary building, on the nuclear island. As shown in DCD Tier 2, Figure 6.4-1, the MCRE encompasses the MCR area, tagging room, operator area, shift supervisor's office, clerk's desk, kitchen, and toilet facilities. The stairwell leading down to Elevation 30.48 m (100'-0") is not part of the MCRE.

DCD Tier 2, Sections 6.4, 9.4-1 and 15.6.5.3; Tables 6.4-1 through 6.4-3 and 15.6.5-2; and Figures 1.2-8, 1.2-25 through 1.2-31, 6.4-1, 6.4-2, and 9.4.1-1, respectively, provide the VES and interfacing VBS descriptions, design parameters, instrumentation (including indications and alarms), and figures. DCD Tier 2, Sections 7.3 and 11.5 provide details of the radiation monitors, including testing and inspection. Chapter 12 of this report evaluates the MCRE shielding design. The redundant, nonseismically qualified, and non-Class 1E-powered pressure instrumentations (PT001A/B) located outside the MCRE, as shown in DCD Tier 2, Figure 6.4-2 and Table 7.5-1, are provided to monitor the common header pressure for the VES storage tanks. The primary postaccident indications of VES operability are provided through the seismically qualified and non-Class 1E-powered differential pressure indicators and the airflow rate instrumentations.

The VES is a self-contained system with no interaction with other zones. As discussed in Section 9.4.1 of this report, normal VBS operation establishes the following conditions to ensure proper VES operation:

- The MCR/TSC HVAC subsystem maintains the MCRE and TSC between 19.4 and 22.8 °C (67 to 73 °F) and between 25 percent and 60 percent relative humidity (RH). The VBS maintains the VES passive cooling heat sink below its initial design ambient air temperature limit of 23.9 °C (75 °F).

- The Class 1E electrical room HVAC subsystem maintains the Class 1E dc equipment rooms between 19.4 and 23.9 °C (67 to 75 °F); the Class 1E electrical penetration rooms, Class 1E battery rooms, Class 1E instrumentation and control rooms, remote shutdown area, RCP trip switchgear rooms, and adjacent corridors between 19.4 and 22.8 °C (67 to 73 °F); and the HVAC equipment rooms between 10 and 29.4 °C (50 to 85 °F). The VBS maintains the Class 1E electrical room emergency passive cooling heat sink below its initial design ambient air temperature limit of 23.9 °C (75 °F).

When the VBS is not available during the 72 hours following the onset of a postulated DBA, the VES serves the function of providing passive heat sinks to limit the temperature rise in the MCR envelope, instrumentation and control rooms, and dc equipment rooms. The heat generated by the equipment, light, and occupants is absorbed by heat sinks that consist primarily of the thermal mass of the concrete that makes up the ceilings and walls of these rooms. As described in DCD Tier 2, Section 6.4.2.2, a metal form is attached to the surface of the concrete, at selected locations, to enhance the heat absorbing capacity of the ceilings. Metallic plates are attached perpendicularly to the ceiling metal form. These plates extend into the room and act as thermal fins to enhance the heat transfer from the room air to the concrete. The temperature in the instrumentation and control rooms following a loss of the VBS is limited to 48.9 °C (120 °F), and the temperature in the dc equipment rooms is limited to 48.9 °C (120 °F) because of the passive heat sinks.

The VES has two safety-related, full-capacity trains to provide emergency air pressurization of the MCRE under emergency conditions. The VES is not required to operate during normal operating conditions. The VES compressed air supply contains a set of storage tanks connected to a main and an alternate air delivery line. Components common to both lines include a manual isolation valve, a pressure regulation valve, and a flow-metering orifice. The system has sufficient redundancy to ensure operation under emergency conditions, assuming the single failure of any one component. Single-active-failure protection is provided by the use of redundant remotely operated isolation valves in the main air delivery line, which are located within the MCR pressure boundary. The Class 1E VES components are connected to independent Class 1E power supplies. Both the VES and the portions of the VBS that isolate the MCRE are designed to remain functional during an SSE or design-basis tornado. In the event of insufficient or excessive flow in the main delivery line, the main delivery line is isolated and the alternate delivery line is manually actuated by opening a manual valve that is located within the MCR pressure boundary. The alternate delivery line contains the same components as the main delivery line, with the exception of the remotely operated isolation valves, and thus is capable of supplying compressed air to the MCRE at the required flow rate.

The 32 emergency air storage tanks are constructed of forged, seamless pipe with no welds, and conform to Section VIII and Appendix 22 of the ASME Code. The design pressure of the air storage tanks is 27,600 kPa (4000 psi). DCD Tier 2, Table 3.2-3, provides data for the VES pressure-regulating valves, flow-metering orifices, remotely operated isolation valves, manual isolation valves, pressure relief isolation valves, and pressure relief dampers. The main airflow path contains a normally open, manually operated valve to isolate and preserve the contents of the air storage tanks in the event of a pressure-regulating valve malfunction. The alternate airflow path contains a normally closed, manually operated valve to manually activate the alternate delivery flowpath in the event the main delivery flow path is inoperable. The VES piping and penetrations for the MCRE are designated as safety Class C. The piping material is alloy steel (ASME Section III, Class 3, Quality Group C), except the piping from the tanks to the subheaders which is stainless steel, as shown in DCD Tier 2, Figure 6.4-2, and is corrosion resistant. Air quality testing is performed quarterly to ensure its acceptability for breathing purposes. A "pigtail" loop at the discharge side of each emergency air storage tank is provided to allow more flexibility in the connection to account for contraction and expansion in the piping. As stated in DCD Tier 2, Section 6.4.2.3, the emergency air storage tanks collectively contain a minimum storage capacity of 8,895 m^3 (314,132 ft^3) at a minimum pressure of 23,400 kPa (3,400 psig). Each pressure-regulating valve, located downstream of the common header, controls downstream pressure to approximately 790 kPa (100 psig) by means of a self-contained pressure control operator. Each flow-metering orifice provides the required flow rate to the MCRE with an upstream pressure of approximately at 790 kPa (100 psig).

Each pressure relief (butterfly) isolation valve is normally closed to prevent interference with the operation of the VBS, and provides a leaktight seal to protect the MCR pressure boundary. Each pressure relief damper, located downstream of the butterfly isolation valve, is set to open on a differential pressure of 3.2-mm (0.125-in.) water gauge with respect to its surroundings.

Two sets of doors, with a vestibule between that acts as an airlock, are provided at the access to the MCRE. The emergency exit door (to the stairs to Elevation 30.48 m (100'-0")) is normally closed, and remains closed under DBA conditions. The penetrations for the piping, ducts, conduits, and electrical cable trays through the MCRE are sealed with a seal assembly compatible with the materials of penetration commodities. The penetration sealing materials are selected to meet GDC 19 criteria for barrier and environment design and remain functional and undamaged during and following an SSE. The electrical cables are routed through internally sealed conduit. Portable, self-contained breathing equipment with air bottles to provide 6 hours of breathable air, along with a supply of protective clothing and respirators for up to 11 MCR occupants, are stored inside the MCRE.

The MCRE is designed for low-leakage construction with no-block walls. The cast-in-place reinforced concrete walls and slabs are constructed to minimize leakage through construction joints and penetrations. DCD Tier 2, Sections 3.8.4.6 and 6.4.2.4 describe the construction techniques and low-leakage features to qualify the MCRE as a low-leakage boundary. Penetration sealing materials are designed to withstand at least a 6.4-mm (0.25-in.) water gauge pressure differential in an air pressure barrier. Penetration sealing material is gypsum cement or equivalent. The non-safety-related VBS air filter housings are designed, tested, and constructed in accordance with RG 1.140, Revision 2, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," and ASME AG-1 and ASME N509 and N510 standards. RG 1.140, Revision 2, and ASME N509 do not allow the use of silicone sealant or any other patching material on filters, housing, mounting frames, or ducts. The non-safety-related VBS ducting is the only HVAC system ducting passing through the MCRE. It is constructed and installed in accordance with Sheet Metal and Air Conditioning Contractors' National Association (SMACNA) standards, and duct joints are sealed with qualified, nonsilicone sealant. DCD Tier 2, Section 6.4.2.4, states specifically that no silicone sealant or any other patching material is used on VBS filters, housing, mounting frame, ducts, or penetrations and VES piping, valves, dampers, or penetrations forming the MCR pressure boundary.

Westinghouse evaluated the effects of three spent fuel pool boiling scenarios on the MCRE. These scenarios consisted of station blackout (SBO) immediately following a full-core offload, an SBO concurrent with a LOCA immediately following a normal refueling, and an SBO concurrent with a LOCA 12 months following a normal refueling. The evaluation results showed that the temperature for the personnel access route and the safety-related valve areas remained below 43 °C (110 °F) (initial temperature of 40 °C (104 °F)) for at least 72 hours after the event and, therefore, the accessibility and equipment qualification were not challenged. DCD Tier 2, Section 6.4.2.4, states that no adverse environmental effects will occur to the MCR sealant materials resulting from postulated spent pool boiling events.

DCD Tier 2, Section 6.4.3.2, states criteria for meeting MCRE air contaminants, including carbon dioxide requirements. The applicant also evaluated both equipment and human performance against the effects of the highest humidity in the MCRE. Westinghouse performed an evaluation using the GOTHIC code and MCRE moisture balance, with respect to time, for a maximum of 11 MCR occupants, during the first 72 hours of an accident. With initial conditions of 24 °C (75 °F) and 60 percent RH, the thermal analysis resulted in the following:

- 31 °C (87 °F) and 41 percent RH at 3 hours, when the non-Class 1E battery heat loads are exhausted

- 29 °C (84 °F) and 45 percent RH at 24 hours, when the battery heat loads are terminated

- 30 °C (86 °F) and 39 percent RH at 72 hours

The staff finds that the above results are within the guidelines of MIL-HDBK-759C, 31 July 1995, "Human Engineering Design Guidelines," and MIL-STD-1472E, 31 October 1996, "Human Engineering."

DCD Tier 2, Section 6.4.4, states that the VES nominally provides 104.5 standard cubic meters per hour (scmh) (65 standard cubic feet per minute (scfm)) of ventilation air to the MCRE from the air storage tanks through the main or alternate air delivery line. Westinghouse also states in this section that the VES flow of 96.5 scmh (60 scfm) is sufficient to pressurize the MCRE to at least (positive) 3.2-mm (0.125-in.) water gauge differential pressure (with respect to the surroundings), and to maintain carbon dioxide concentration below 0.5 percent by volume for a maximum occupancy of 11 persons inside the MCRE. This will maintain air quality within the guidelines of Table 1 and Appendix C, Table C-1, to American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 62-1989, "Ventilation for Acceptable Indoor Air Quality." Westinghouse's latest leak-rate analysis assumes a MCRE occupancy limited to 11 persons throughout the 72-hour period following an accident and is predicated on the validation process task analysis described in DCD Tier 2, Chapter 18.

The safety-related compressed air storage tanks are sized to provide the airflow to the MCRE for 72 hours. During a nonradiological emergency, the emergency air storage tanks can be refilled via a connection to the breathable quality air compressor in the compressed and instrument air system (CAS). These tanks can also be refilled from portable supplies by an installed connection in the CAS.

DCD Tier 2, Section 6.4.4, states that the analysis of onsite chemicals is described in DCD Tier 2, Table 6.4-1, and their locations are shown in DCD Tier 2, Figure 1.2-2. Analysis of these sources is in accordance with RG 1.78, Revision 1, "Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," and shows that these sources do not represent a toxic hazard to MCRE personnel.

The NRC staff requested additional information as part of the RAI 410.007 to (a) verify that the chemicals listed in DCD Tier 2, Table 6.4-1, "Onsite Chemicals," were evaluated using the methodology in NUREG-0570, "Toxic Vapor Concentrations in the Control Room Following a

Postulated Accidental Release," and that these chemicals do not represent a toxic hazard to control room operators; (b) verify that COL applicants are responsible for (i) the amount and location of possible sources of toxic chemicals (as shown in DCD Tier 2, Table 6.4-1, and their locations, as shown in DCD Tier 2, Figure 1.2-2) in or near the plant, (ii) seismic Category I Class 1E toxic gas monitoring, as required, (iii) assessing control room protection for toxic chemicals, and (iv) evaluating offsite toxic releases (including the potential for toxic releases beyond 72 hours) in accordance with RG 1.78, Revision 1, and meet the requirements of 10 CFR 50.34(f)(2)(xxviii) (TMI Action Plan Item IIID.3.4) and GDC 19; add RG 1.78, Revision 1, to DCD Tier 2, Section 6.4.8, "References" because RG 1.78, Revision 1, replaces both RG 1.78, Revision 0, and RG 1.95, Revision 1, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release"; (d) delete reference to RG 1.95 from DCD Tier 2, Section 6.4.7; (e) revise Appendix 1A to assess the conformance with RG 1.78, Revision 1, and revise DCD Tier 2, Sections 2.2, 6.4, 9.4.1, and 9.5.1, and Table 1.9-1 (Sheet 7 of 15) to correctly state the reference as "RG 1.78 December 2001, Revision 1"; and (f) revise the reference list in TS bases B.3.7.6 to add a reference to ASHRAE Standard 62-1989.

In a letter dated March 26, 2003, Westinghouse revised the response to RAI 410.007 by providing additional information as requested by the NRC staff and committing to revise DCD Tier 2, Sections 6.4.4, 6.4.7, and 6.4.8; Appendix 1A to DCD Tier 2; and DCD Tier 2, Chapter 16, B3.7.6. Westinghouse incorporated these changes in the DCD. However, the staff noted that the DCD still needed to include the response to RAI 410.007(a), Revision 2, dated March 26, 2003. Specifically, the DCD needed to include a statement that Westinghouse had verified that the chemicals listed in DCD Tier 2, Table 6.4-1, "Onsite Chemicals," were evaluated using the methodology in NUREG-0570 and concluded that these chemicals do not represent a toxic hazard to control room operators. In a letter dated May 21, 2003, Westinghouse revised the response to RAI 410.007 and committed to placing this information in the DCD. This was Confirmatory Item 6.4-1 in the DSER. In a subsequent DCD revision, the staff verified that Westinghouse included this statement. Therefore, Confirmatory Item 6.4-1 is closed.

The staff performed an independent evaluation. On the basis of the data Westinghouse furnished regarding quantity, sizes, and locations, the staff concludes that these onsite chemicals meet the guidelines of RG 1.78, Revision 1.

In DCD Tier 2, Section 6.4.7, Westinghouse states that COL applicants referencing the AP1000 design are responsible for the amount and location of possible sources of toxic chemicals in or near the plant, as well as for seismic Category 1, Class 1E toxic gas monitoring, as required (detectors where necessary to permit automatic isolation of the control room). Additionally, it further states that RG 1.78, Revision 1, addresses control room protection for toxic chemicals, and that Westinghouse evaluated offsite releases (including the potential for toxic releases beyond 72 hours in accordance with the guidelines of RG 1.78) in order to meet the requirements of the TMI Action Plan Item III.D.3.4 and GDC 19.

As discussed previously, the non-safety-related VBS subsystem (MCR/TSC HVAC subsystem) isolates the MCRE and/or TSC area from the normal outdoor air intake. It provides filtered outdoor air to pressurize the MCRE and TSC areas to a positive pressure of at least 3.2-mm (0.125-in.) water gauge, with respect to the surrounding areas, when high gaseous radioactivity is detected in the MCRE supply air duct. The non-safety-related supplemental air filtration units have a fission product removal efficiency of 90 percent for charcoal adsorbers and 99 percent for high-efficiency particulate air (HEPA) filters.

No credit was taken for fission product removal by HEPA filters and charcoal adsorbers in the supplemental air filtration units in evaluating the control room radiological habitability.

The VBS system is not designed as a postaccident ESF atmospheric cleanup system and has no safety-grade source of power; therefore, it was not credited in evaluating conformance with GDC 19. Section 9.4 of this report provides the staff's evaluation of the VBS.

The location of the single control room outside air intake serving the VBS conforms with the guidance of Section 6.4 of the SRP and RG 1.95 because it is located more than 15.2 m (50 ft) vertically below and more than 30.5 m (100 ft) laterally away from the plant discharge. The air intake is located on the roof of the auxiliary building at Elevation 46.63 m (153'-0"), and is protected by an intake enclosure. The VBS redundant radiation monitors are located inside the MCRE. DCD Tier 2, Figure 9.4.1-1, depicts the radiation monitors and outside air isolation dampers. The outside air is continuously monitored by redundant smoke monitors at the outside air intake. As stated in DCD Tier 2, Section 9.4.1.2.1.1, the VBS supply, return, and toilet exhaust ducts are the only HVAC penetrations in the MCRE; as stated in DCD Tier 2, Section 6.4.4, no radioactive materials are stored or transported near the MCRE.

The flue gas exhaust stacks of the onsite standby power diesel generators are located in excess of 46 m (150 ft) away, and the onsite standby power system fuel oil storage tanks are located in excess of 91 m (300 ft) away from the fresh air intakes of the MCR to preclude the drawing of combustion fumes or smoke from an oil fire into the MCR.

GDC 19 requires that the control room be designed to provide adequate radiation protection permitting personnel to access and occupy the control room under accident conditions. As applied to the AP1000 design, GDC 19 requires that adequate radiation protection be provided to ensure that radiation exposures will not exceed 0.05 Sv (5 rem) TEDE, as defined in 10 CFR 50.2, for the duration of the accident. Westinghouse proposed that this requirement be met by incorporating sufficient shield walls and by installing the redundant non-safety-related supplemental air filtration units (VBS) and a safety-related emergency bottled air pressurization system (VES). Section 9.4 of this report provides a discussion of the staff's review of the applicant's analysis of the capability of the non-safety-related VBS to mitigate the consequences of a design-basis accident in the MCR and TSC.

Westinghouse submitted the results of radiological consequence analyses for personnel in the MCR during design-basis accidents in DCD Tier 2, Section 6.4.4. Details of the analysis assumptions for modeling the doses to MCR personnel were submitted in DCD Tier 2, Section 15.6.5.3. Section 15.3 of this report discusses the staff's review of the applicant's analysis.

To verify the Westinghouse assessments, the staff performed independent radiological consequence calculations for DBAs with the VES under high-high radiation level as described in the DCD Tier 2, Section 6.4. The staff used the following information in its analyses:

- reactor accident source terms based on NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants," and RG 1.183, "Alternative Radiological Source Terms for Evaluating Design-Basis Accidents at Nuclear Power Reactors"

- control room χ/Q values and control room unfiltered in-leakage rates provided by Westinghouse

- control room occupancy factors referenced in Section 6.4 of the SRP

Because of issues with aerosol removal and atmospheric dispersion as discussed in DSER Open Items 15.3-1 and 15.3-2, the staff was unable to complete its review of the applicant's analyses of the radiological consequences in the MCR during design-basis accidents. This was Open Item 6.4-1 in the DSER. With the resolution of DSER Open Items 15.3-1 and 15.3-2, the staff has completed its review, and DSER Open Item 6.4-1 is closed.

The staff finds that the VES, under high-high radiation conditions, as described in DCD Tier 2, Section 6.4, is capable of mitigating the dose in the MCR following DBAs to meet the dose criteria specified in GDC 19, as applied to the AP1000 design. Section 15.3 of this report discusses the staff's review of the applicant's analysis of control room habitability and the staff's independent confirmatory radiological consequence analyses for the control room operators.

DCD Tier 2, Section 6.4.7, states that COL applicants referencing the AP1000 certified design are responsible for verifying that the procedures and training for control room habitability are consistent with the intent of GSI 83 (see DCD Tier 2, Section 1.9). This is COL Action Item 6.4-1.

The VES is tested and inspected at appropriate intervals, in accordance with the surveillance and frequency requirements specified in the TS. The leaktightness testing of the MCRE is conducted in accordance with the frequency specified in the TS. Connections are provided for sampling the air supplied from the CAS and for periodic sampling of the air stored in the emergency air storage tanks. In accordance with the TS, air samples from the emergency air storage tanks are taken quarterly (every 92 days) and analyzed to ensure conformance with the guidelines of Table 1 and Appendix C, Table C-1, of ASHRAE Standard 62-1989.

DCD Tier 2, Table 15.6.5-2, provides the MCRE volume and maximum unfiltered air in-leakage (infiltration) rates as follows. The MCRE volume is 1,011 m^3 (35,700 ft^3). The maximum unfiltered air in-leakage (infiltration) into the MCRE under accident conditions is 4.02–8.04 scmh (2.5–5.0 scfm) when the VES is operating. The maximum unfiltered air in-leakage (infiltration) into the MCRE during a high gaseous radioactivity signal while the VBS is operating is 145 scmh (90 scfm). The AP1000 design includes an air-lock type, double door vestibule style entrance for the MCRE to minimize contaminated air from entering the MCRE as a result of egress and ingress, and to maintain the MCRE at 3.2-mm (0.125-in.) water gauge positive pressure, with respect to surrounding areas.

DCD Tier 2, Section 6.4.5.4, states that "Testing for main control room in-leakage during VES [main control room emergency habitability system] operation will be conducted in accordance with ASTM E741 [2000, "Standard Test Method for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution"].

In RAI 410.007, the NRC staff stated that it anticipates that the testing frequency for air in-leakage will be 5 to 6 years, based on joint efforts currently pursued by the industry and NRC staff to address control room habitability issues. Therefore, the AP1000 design should include a commitment to resolving the in-leakage testing frequency issue in accordance with the anticipated outcome of the joint effort between the NRC staff and industry.

In a letter dated November 15, 2002, Westinghouse responded that the NRC staff and the industry are working on in-leakage testing; however, it is not reasonable to commit to a standard that does not currently exist. Westinghouse, therefore, is not providing a commitment to have the VES meet the anticipated requirements currently being pursued. Westinghouse further stated that the VES design addresses in-leakage and meets the codes and standards that were in effect 6 months prior to the date of the AP1000 design certification application (March 28, 2002). The NRC staff disagreed with Westinghouse's position on the testing frequency for unfiltered-in-leakage, as provided in its response to RAI 410.007, and stated that Westinghouse needs to revise its RAI 410.007 response and DCD Tier 2, Section 6.4.5.4, to provide an in-leakage testing frequency commitment commensurate with the anticipated outcome of the joint effort between the NRC staff and industry. In a letter dated February 14, 2003, Westinghouse provided additional information to revise its original response to RAI 410.007 asserting that DCD Tier 2, Section 6.4.5.4, will be revised to state that, "Testing for main control room inleakage during VES operation will be conducted in accordance with ASTM E741"; DCD Tier 2, Section 6.4.7, will be revised to state that, "The Combined License applicant will provide the testing frequency for the main control room inleakage test discussed in DCD Tier 2, Section 6.4.5.4." In addition, Westinghouse revised DCD Tier 2, Table 1.8-2, "Summary of AP1000 Standard Plant Combined License Information Items," Item 6.4-3, to refer to DCD Tier 2, Section 6.4.7 for the MCR in-leakage test frequency. Westinghouse incorporated these changes into the DCD. This is COL Action Item 6.4-2; the staff finds this approach to be acceptable because the COL applicant will actually measure the control room unfiltered inleakage at a frequency that will be reviewed by the staff at the COL stage.

DCD Tier 2, Section 6.4.2.2, states that, in the unlikely event that power to the VBS is not available for more than 72 hours and the outside air is acceptable radiologically and chemically, MCR habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR. Doors and ducts may be opened to provide a supply pathway and an exhaust pathway for the ancillary fans. Likewise, outside air is supplied to Divisions B and C instrumentation and control rooms to maintain the ambient temperature below the qualification temperature of the equipment. It is expected that outside air will be acceptable within 72 hours following a radiological and toxic gas release. The outside air pathway to the ancillary fans is provided through the VBS air intake opening located on the roof, the mechanical room at floor Elevation 41.22 m (135'-3"), and the VBS supply duct. Warm air from the MCRE is vented to the annex building through stairway S05, and into the remote shutdown room and the clean access corridor at Elevation 30.48 m (100'-0"). As stated in DCD Tier 2, Section 9.4.1.1.2, the post-72 hour design basis of the VBS is (1) to maintain the MCR below a temperature approximately 2.5 °C (4.5 °F) above the average outdoor air temperature, and (2) to maintain Divisions B and C instrumentation and control rooms below the qualification temperature of the instrumentation and control equipment. Section 8.3 of this report discusses the staff's evaluation of the post-72 hour power supply.

Chapter 14 of this report discusses preoperational testing. It includes verification that a minimum VES airflow rate of 104.5±8.04 scmh (65±5 scfm) will pressurize the MCRE to 3.2-mm (0.125-in.) water gauge with respect to the surrounding spaces. The maximum unfiltered air in-leakage (infiltration) rate of 4.02–8.04 scmh (2.5–5.0 scfm) during accident conditions when the VES is in operation will be verified in accordance with ASTM E741, "Standard Test Method for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution." The 72-hour capacity of air storage tanks will be verified to be in excess of 8,418 standard cubic meters (314,132 standard cubic feet), at a minimum pressure of 23,442 kPa (3,400 psig). Heat loads will be verified to be below the values in DCD Tier 2, Table 6.4-3. VBS MCRE isolation valves will be tested to verify the leaktightness of the valves. Section 11.5 of this report discusses testing and inspection of the VBS safety-related radiation monitors. The air quality within the MCR/TSC environment will be confirmed to be within the guidelines of Table C-1 of ASHRAE Standard 62-1989 by analyzing air samples taken during pressurization testing. The staff finds the preoperational testing to be acceptable because it will verify the ability of the MCRE to limit unfiltered in-leakage and maintain acceptable air quality and a suitable environment for the operators.

The VES indications and alarms listed in DCD Tier 2, Table 6.4-2, are located in the MCR. Sections 7.3 and 11.5 of this report discuss actuation and radiation monitoring instrumentation for the VBS and VES.

Westinghouse evaluated the MCRE structure for protection against the environmental requirements, including soil and water pressure, on substructure, tornado pressure drop, thermal stresses, and pipe and pipe rupture loads in DCD Tier 2, Sections 3.3, 3.6, and 3.8. Westinghouse also stated that the flood protection measures for seismic Category 1 SSCs are designed in accordance with RG 1.102, "Flood Protection for Nuclear Power Plants," and RG 1.59, "Design Basis Floods for Nuclear Power Plants." Additionally, Westinghouse states the following in DCD Tier 2, Sections 3.5 and 3.6:

- Internally generated missiles (outside the containment) from rotating and pressurized components are either not considered credible or evaluated as described in DCD Tier 2, Section 3.5.1.1.

- Protection from high-energy lines near the control room is evaluated in DCD Tier 2, Section 3.6.1.2.

Therefore, Westinghouse concludes that the habitability systems will be protected against dynamic effects that may result from possible failures of such lines.

In Sections 3.4.1, 3.5.1.1, 3.5.2, and 3.6.1 of this report, the staff documents its evaluation of the protection against floods, internally and externally generated missiles, and high- and moderate-energy pipe breaks. The staff concludes that the control room habitability systems satisfy GDC 4, as it relates to protection of the system against floods, internally generated missiles, and piping failures.

As described above, the staff evaluated the VES for conformance with GDC 4, 5, and 19, as referenced in Section 6.4 of the SRP, and consequently with the subject SRP acceptance criteria. The staff finds the VES acceptable.

Control Room Habitability and Toxic Chemicals

Westinghouse specifies in DCD Tier 2, Section 6.4.7, that the evaluation of possible harmful effects to control room personnel from toxic chemicals located at or near the site will be addressed by the COL applicant. The staff finds this acceptable. This is COL Action Item 6.4-3.

6.5 Fission Product Removal and Control Systems

6.5.1 ESF Plant Atmosphere Filtration Systems

This section is not applicable to the AP1000 design.

6.5.2 Containment Spray System

The AP1000 design does not have a safety-related containment spray system. Its design involves removal of airborne activity by a natural process that does not depend on sprays (i.e., sedimentation, diffusiophoresis, and thermophoresis). Much of the nongaseous airborne activity would eventually be deposited in the containment sump solution. Long-term retention of iodine in the containment sump following DBAs requires adjustment of the sump's pH. For the AP1000 design, this adjustment is accomplished through the PXS discussed in DCD Tier 2, Section 6.3, "Passive Core Cooling System." The FPS provides a non-safety-related containment spray function for accident management following a severe accident. This design is not credited in any analysis. DCD Tier 2, Section 15.6.5, "Loss-of-Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary," further discusses natural mechanisms for removal of airborne activity.

The AP1000 design does include a non-safety-related containment spray as part of the FPS, and which is used to enhance the natural removal mechanisms in the unlikely event of a severe accident. The containment isolation portion of this system is safety-related. Section 19.2.3.3.9 of this report evaluates the non-safety-related containment spray system.

6.5.3 Fission Product Control Systems

The AP1000 has no active system to control fission products in the containment following a postulated accident. The only fission product control system is the primary containment. DCD Tier 2, Appendix 15B discusses satisfactory removal of airborne activity (elemental iodine and particulates) from the containment atmosphere by natural removal processes (e.g., deposition and sedimentation) without the use of containment spray. The AP1000 design does not require active fission product control systems to meet the regulatory requirements (dose limits in 10 CFR 50.34). These natural fission product control mechanisms and the limited containment leakage result in offsite doses that are less than those specified in 10 CFR 50.34.

6.6 Inservice Inspection of Class 2 and 3 Components

The staff reviewed DCD Tier 2, Section 6.6, "Inservice Inspection of Class 2 and 3 Components," in accordance with Section 6.6, "Inservice Inspection of Class 2 and 3 Components," of the SRP. The SRP, Section 6.6, states that the requirements for periodic inspection and testing of Class 2 and 3 systems in GDC 36, 37, 39, 40, 42, 43, 45, and 46, are specified in 10 CFR 50.55a and detailed in Section XI of the ASME Code.

The ISI program for ASME Class 2 and Class 3 components relies upon these design provisions to allow performance of ISI. Compliance with these GDC ensures that the design of the safety systems will allow accessibility of important components so that periodic inspections can be performed to detect degradation, leakage, signs of mechanical or structural distress caused by aging, and fatigue or corrosion, prior to the ability of the systems to perform their intended safety functions being jeopardized.

GDC 36 requires that the ECCS be designed to permit periodic inspection of important components to assure the integrity and capability of the system.

GDC 37 requires that the ECCS be designed to permit periodic pressure testing to assure the structural and leaktight integrity of its components.

GDC 39 requires that the containment heat removal system be designed to permit periodic inspection of important components to assure the integrity and capability of the system.

GDC 40 requires that the containment heat removal system be designed to permit periodic pressure testing to assure the structural and leaktight integrity of its components.

GDC 42 requires that the containment atmosphere cleanup systems be designed to permit periodic inspection of important components to assure the integrity and capability of the systems. As discussed below, this criterion is not applicable to the AP1000 design.

GDC 43 requires that the containment atmosphere cleanup systems be designed to permit periodic pressure testing to assure the structural and leaktight integrity of their components. As discussed below, this criterion is not applicable to the AP1000 design.

GDC 45 requires that the cooling water system be designed to permit periodic inspection of important components to assure the integrity and capability of the system. As discussed below, this criterion is not applicable to the AP1000 design.

GDC 46 requires that the cooling system be designed to permit periodic pressure testing to assure the structural and leaktight integrity of its components. As discussed below, this criterion is not applicable to the AP1000 design.

Compliance with the preservice and inservice examination requirements of 10 CFR 50.55a, as detailed in Section XI of the ASME Code, constitutes an acceptable basis for satisfying, in part, the requirements of GDC 36, 37, 39, 40, 42, 43, 45, and 46. Subsection II of the SRP states that GDC 36, 37, 39, 40, 42, 43, 45, and 46 require that the respective safety systems addressed by these criteria be designed such that they permit periodic inspection, pressure testing, and functional testing of system components and piping.

The following six specific requirements apply to the review of DCD Tier 2, Section 6.6:

(1) Components Subject to Inspection

The applicant's definition of ASME Code Class 2 and 3 components and systems subject to an inservice inspection (ISI) program is acceptable if it is in agreement with the definitions of ASME Code, Section III, Article NCA-2000, "Classification of Components and Supports," which is invoked by 10 CFR 50.55a.

(2) Accessibility

As required by 10 CFR 50.55a(g)(3)(ii), ASME Code Class 2 and Class 3 components and supports must be designed and provided with access to enable the performance of inservice examination of such components and to meet the preservice examination requirements set forth in ASME Section XI. ASME Section XI, Subarticle IWA-1400(b), states that it is the owner's responsibility for the design and arrangement of system components to include allowances for adequate access and clearances to conduct examinations and tests. ASME Section XI, Subarticle IWA-1500, establishes the requirements for accessibility in order to facilitate examination of components.

Provisions for accessibility must include (a) access for the inspector, examination personnel, and equipment necessary to conduct the examinations, (b) sufficient space for removal and storage of structural members, shielding, and insulation, (c) installation and support of handling machinery where required to facilitate removal, disassembly, and storage of equipment, components, and other materials, (d) performance of examinations alternative to those specified in the event structural defects or indications are revealed that may require such alternative examination, and (e) performance of necessary operations associated with repairs or installation of replacements.

(3) Examination Categories and Methods

The applicant's examination categories and methods of examination are acceptable if they are in agreement with the requirements of IWA-2000, IWC-2000, and IWD-2000 ("Examination and Inspection") of Section XI of the ASME Code.

(4) Evaluation of Examination Results

The methods for evaluation of the results are acceptable if they are in agreement with the requirements of IWC-3000 and IWD-3000 ("Acceptance Standards") of Section XI of the ASME Code.

(5) System Pressure Tests

The system pressure testing is acceptable if it meets the requirements of IWA-5000, "System Pressure Tests," of Section XI of the ASME Code.

(6) Augmented ISI to Protect against Postulated Piping Failure

High-energy fluid piping between containment isolation valves receives an augmented 100-percent volumetric examination of circumferential and longitudinal pipe welds in accordance with the guidance of SRP 3.6.2, "Determination of Rupture Locations and Dynamic Effects Associated with Postulated rupture of Piping."

Summary of Technical Information

DCD Tier 2, Section 6.6, "ISI of Class 2 and 3 Components," indicates preservice, ISI, and testing of ASME Code Class 2 and 3 components are performed in accordance with Section XI of the ASME Code, including addenda required by 10 CFR 50.55a(g). This includes all ASME Code Section XI mandatory appendices.

The inspection program should delineate the specific edition and addenda of the Code used to determine the requirements for the inspection and testing plan for the initial and subsequent inspection intervals. DCD Tier 2, Section 5.2.1.1, indicates the baseline used for the evaluation done to support the safety analysis report and the Design Certification is the 1998 Edition through the 2000 Addenda. The Code includes requirements for system pressure tests for active components. Section XI, IWA-5000, defines the requirements for system pressure tests and visual examinations. These tests verify the pressure boundary integrity in conjunction with ISI.

Westinghouse stated that ASME Code Class 2 and 3 components are designed so that access is provided in the installed condition for visual, surface, and volumetric examinations specified by the ASME Code. Westinghouse stated that design provisions, in accordance with ASME Section XI, IWA-1500, are formally implemented in the Code Class 2 and 3 component design process. Removable insulation is provided on piping systems requiring volumetric and surface inspection. Removable hangers and pipe whip restraints are provided, where practical and necessary, to facilitate ISI. Working platforms are provided in areas requiring inspection and servicing of pumps and valves. Temporary or permanent platforms, scaffolding, and ladders are provided to facilitate access to piping welds. The components and welds requiring ISI are designed to allow for the application of the required ISI methods. Westinghouse stated that sufficient clearances for personnel and equipment, maximized examination surface distances, two-sided access, favorable materials, weld joint simplicity, elimination of geometrical interferences, and weld surface preparation all contribute to satisfying the inspectability and accessibility requirements of 10 CFR 50.55a(g)(3)(ii) and ASME Section XI, Subarticle IWA-1500. Westinghouse stated that space is provided to handle and store insulation, structural members, shielding, and other material related to the inspection. Suitable hoists and other handling equipment, lighting, and sources of power for inspection equipment are installed at appropriate locations.

Westinghouse also stated that COL applicants referencing the AP1000 certified design will prepare a preservice inspection program and an ISI program for ASME Code, Section III, Class 2 and 3 systems, components, and supports. The preservice/ISI programs will address the equipment and techniques used. This is COL Action Item 6.6-1. Finally, COL applicants referencing the AP1000 certified design will address the controls to preserve accessibility and inspectability for ASME Code, Section III, Class 2 and 3 components and piping during construction or other postdesign certification activities. This is COL Action Item 6.6-2. The preservice/ISI programs will comply with applicable provisions of 10 CFR 50.55a(b)(2).

Staff Evaluation

The staff's evaluation of ISI of ASME Code Class 2 and 3 components is divided into the following seven sections: components subject to inspection, accessibility, examination categories and methods, evaluation of examination results, system pressure tests, augmented ISI to protect against postulated piping failure, and GDC.

(1) Components Subject to Inspection

The AP1000 design classifies components as ASME Code Class 2 and 3 in accordance with the criteria provided in DCD Tier 2, Section 3.2.2, and reviewed in the corresponding section of this report. The design follows ASME Code, Section III, as required by 10 CFR 50.55a. Thus, Class 2 and 3 components subject to inspection are in agreement with definitions acceptable to the staff in ASME Code, Section III, Article NCA-2000.

(2) Accessibility

The AP1000 design follows the ASME Code provisions for accessibility which include (a) access for the inspector, examination personnel, and equipment necessary to conduct the examinations, (b) sufficient space for removal and storage of structural members, shielding, and insulation, (c) installation and support of handling machinery where required to facilitate removal, disassembly, and storage of equipment, components, and other materials, (d) performance of examination alternatives to those specified in the event structural defects or indications are revealed that may require such alternative examination, and (e) performance of necessary operations associated with repairs or installation of replacements. As required by 10 CFR 50.55a, the design of the pressure-retaining components meets the requirements of ASME Code, Section XI, Section IWA-1500, "Accessibility," thus meeting requirements acceptable to the staff with respect to accessibility.

The staff reviewed DCD Tier 2, Section 6.6, to assure that compliance with the regulations for the design of the ASME Code Class 2 and Class 3 components would be met. The regulations and the ASME Code require that inspectability and accessibility be designed into the system in order that meaningful preservice and ISIs can be performed prior to and during the life of the plant. If the provisions allowing for inspection and access for performance of preservice and ISI are not designed into the plant, the COL applicant will not be able to perform the required testing. This testing is necessary to assure that the components can perform their intended functions and do not degrade due to service-related failures.

The Westinghouse AP1000 design incorporates lessons learned to ensure that the ASME Code Class 2 and 3 components are designed to allow for the application of the required ISI methods (i.e., maximized examination surface distances, elimination of geometric interferences, weld joint simplicity, favorable materials, proper weld surface preparation, removable insulation, two-sided access, and removable whip restraints and hangers) to facilitate access for the performance of inspection. According to staff experience, these aspects of the design have been the major source of licensees' requests for relief from the ASME Code. Westinghouse also stated that access for testing, by designing sufficient platforms, and lighting, as well as installing temporary platforms and ladders to allow inspection of piping and welds, is inherent in the AP1000 design.

By effectively eliminating these interferences by designing for inspectability and accessibility, the AP1000 design meets the requirements of 10 CFR 50.55a(g)(3)(ii) and ASME IWA-1500, which enables the COL applicant to perform preservice and ISIs, and is, therefore, acceptable. The applicant has stated that relief from Section XI requirements will not be required for ASME Code, Section III, Class 2 and 3 pressure-retaining components in the AP1000 plant for the baseline design certification Code. Future changes in the Section XI requirements could, however, necessitate relief requests. The staff concludes that this approach is consistent with the requirements of 10 CFR 50.55a, and is therefore acceptable.

(3) Examination Categories and Methods

The ISI program will follow ASME Code, Section XI, as required by 10 CFR 50.55a. Thus, the examination categories and methods will be in agreement with requirements acceptable to the staff in IWA-2000, IWC-2000, and IWD-2000 of Section XI of the Code. The staff will review the ISI program at the COL stage to ensure that it meets the applicable requirements of the ASME Code, Section XI.

(4) Evaluation of Examination Results

The ISI program will follow ASME Code, Section XI, as required by 10 CFR 50.55a. Thus, the evaluation of examination results will be in agreement with requirements acceptable to the staff in IWC-3000 and IWD-3000 of Section XI of the Code. The staff will review the ISI program at the COL stage to ensure that the examination results will be evaluated in accordance with the applicable requirements of the ASME Code, Section XI.

(5) System Pressure Tests

The ISI program will follow ASME Code, Section XI, as required by 10 CFR 50.55a. Thus, the system pressure testing will meet requirements acceptable to the staff in IWA-5000 of Section XI of the Code. The staff will review the ISI program at the COL stage to ensure that the system pressure test requirements of the ASME Code, Section XI will be met.

(6) Augmented ISI to Protect against Postulated Piping Failure

DCD Tier 2, Section 6.6, indicates that the COL applicant will develop an augmented inspection program for high-energy fluid system piping between containment isolation valves. Such a program is also developed for those cases in which no isolation valve is used inside containment between the first rigid pipe connection to the containment penetration, or the first pipe whip restraint inside containment, and the outside isolation valve. This program will provide for 100-percent volumetric examination of circumferential and longitudinal pipe welds during each inspection interval conducted according to the ASME Code, Section XI. This program will cover the break exclusion portion of the high-energy fluid systems described in DCD Tier 2, Sections 3.6.1 and 3.6.2. Because the proposed program satisfies the criteria of SRP Section 6.6, the staff finds this augmented ISI program to be acceptable.

(7) GDC

The applicability of the GDC was reviewed for the AP1000 design. Because of the passive design concepts of the AP1000 design, portions of systems that had been considered safety-related in existing LWR designs and evolutionary plants are not necessarily safety-related in the AP1000 design. Consequently, these systems, or portions thereof, are not classified as ASME Code Class 2 or 3 systems; rather, they are classified as non-ASME Code systems. As non-ASME Code systems, they are not subject to ISI and periodic pressure testing required by the ASME Code. The staff, therefore, reviewed the applicability of the above GDC as they relate to the periodic inspection and testing of those portions of the ECCS, containment heat removal system, containment atmosphere cleanup system, and cooling water system that exist in the AP1000 design.

Emergency core cooling is performed by the AP1000 PXS, as described in DCD Tier 2, Section 6.3. Section 6.3 of this report describes the staff's evaluation of the use of the PXS in lieu of an ECCS. This system is safety-related and contains ASME Code Class 1, 2, and 3 components. As such, this system is subject to the periodic inspection and pressure testing required by the ASME Code. This system is designed to permit periodic inspection and testing of components. Thus, the staff finds that the PXS meets the requirements of GDC 36 and 37.

Containment heat removal is performed by the PCS, as described in DCD Tier 2, Section 6.2.2. The PCS utilizes the steel containment shell to transfer heat from the interior through natural convection. Heat is removed from the shell by a direct-flow natural convection design and a passive external cooling system. Section 6.2.2 of this report discusses the staff's evaluation of the PCS. This system is safety-related and contains ASME Code Class 3 components. As such, this system is subject to the periodic inspection and pressure testing required by the ASME Code. The system piping and components are designed to permit access for periodic inspection and testing of equipment. Thus, the staff finds the PCS meets the requirements of GDC 39 and 40.

The AP1000 design does not use a containment atmosphere cleanup system, as found in existing LWRs. The AP1000 does not rely on active systems for the removal of activity from the containment atmosphere postaccident cleanup functions. The containment atmosphere is depleted of elemental iodine and of particulates as a result of natural processes within containment. However, a portion of the FPS that serves a non-safety-related containment spray function for severe accident management includes equipment and valves, such as the fire pumps and fire main header. Section 6.5.2 and Chapter 19 of this report provide the staff's evaluation of the containment spray system. Because the containment spray system has no safety function, the system components are not classified as ASME Code class, except for those portions that function as containment isolation. Those portions are classified as ASME Code Class 2. As such, no periodic inspection and pressure testing requirements apply, except for those portions of the containment spray system classified as ASME Code Class 2. The staff finds that ASME Code, Section XI, inspection and testing of a containment atmosphere cleanup system, as provided by the containment spray system, are not required because the safety-related functions of the containment atmosphere cleanup do not rely on active systems. Therefore, GDC 42 and 43 are not applicable to the AP1000 design.

The AP1000 design utilizes a component cooling water system to support the normal operation of safety-related components. However, none of the safety-related components require cooling water to perform their safety-related function. Safety-related cooldown and decay heat removal functions are provided by the PXS and the PCS. Section 9.2.2 of this report discusses the staff's evaluation of the component cooling water system. Because this system is not safety-related, the system components are not classified as ASME Code Class 1, 2, or 3, except for those portions that function as containment isolation. These system components are classified as ASME Code Class 2. As such, no periodic inspection and pressure testing requirements apply, except for those portions classified as ASME Code Class 2. The staff finds that ASME Code, Section XI, inspection and testing of the component cooling water system are not required because the safety-related functions of the component cooling water system are subsumed by the passive systems discussed above. Therefore, GDC 45 and 46 are not applicable to the AP1000 design.

Conclusions

The staff concludes that the AP1000 ISI program for Code Class 2 and 3 components is acceptable and meets the inspection and pressure-testing requirements of GDC 36, 37, 39, and 40, as well as the requirements of 10 CFR 50.55a with regard to preservice and inservice inspectability of these components.

7. INSTRUMENTATION AND CONTROLS

7.1 Introduction

The AP1000 Design Control Document (DCD) Tier 2, Chapter 7, "Instrumentation and Controls," contains the description of and commitments pertaining to the primary instrumentation and control (I&C) systems of the AP1000 design. The I&C systems provide protection against unsafe reactor operation during steady-state and transient power operations. In addition, they initiate selected protective functions to mitigate the consequences of design-basis events and accidents and to safely shut down the plant either by automatic means or by manual actions.

DCD Tier 2, Section 7.1, "Introduction," describes the AP1000 general I&C system architecture, with specific emphasis on the design and design process of the protection and safety monitoring system (PMS). DCD Tier 2, Section 7.2, "Reactor Trip," discusses the I&C aspects of the reactor trip function. DCD Tier 2, Section 7.3, "Engineered Safety Features," addresses the engineered safety feature (ESF) actuations. DCD Tier 2, Section 7.4, "Systems Required for Safe Shutdown," discusses the systems in the AP1000 design that are required for safe shutdown. DCD Tier 2, Section 7.5, "Safety-Related Display Information," discusses safety-related display information. DCD Tier 2, Section 7.6, "Interlock Systems Important to Safety," discusses interlocks important to safety. DCD Tier 2, Section 7.7, "Control and Instrument Systems," describes the control systems and diverse actuation system of the AP1000.

7.1.1 Acceptance Criteria

The acceptance criteria used as the basis for the review of these systems by the staff of the U.S. Nuclear Regulatory Commission (NRC) are set forth in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," hereafter referred to as the SRP. This document sets forth a method for compliance with applicable sections of Title 10, Part 50, of the Code of Federal Regulations (10 CFR Part 50), "Domestic Licensing of Production and Utilization Facilities," and 10 CFR Part 52, "Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants." Chapter 7, "Instrumentation and Controls," Revision 4, dated June 1997, is the primary section of the SRP used for this review.

Chapter 7 of the SRP provides guidance for the review of I&C systems in light-water nuclear power plants. Revision 4 identifies the procedures for reviewing digital systems. These procedures can be found in SRP Chapter 7, Appendix 7.0-A; SRP Chapter 7, Appendix 7.1-A; SRP Sections 7.1, 7.8, and 7.9; and SRP Branch Technical Positions (BTPs) Instrumentation and Controls Branch (HICB)-11, HICB-14, HICB-17, HICB-18, HICB-19, and HICB-21. Appendix 7.1-C to the SRP and SRP Sections 7.2 through 7.7 provide additional review guidance.

The following regulations are also identified in Chapter 7 of the SRP as being applicable to digital I&C systems:

- 10 CFR 50.55a(a)(1)
- 10 CFR 50.55a(h)

- 10 CFR 50.62
- Appendix A to 10 CFR Part 50, "General Design Criteria for Nuclear Power Plants"

In particular, the following General Design Criteria (GDC) are applicable:

- GDC 1, "Quality Standards and Records"
- GDC 2, "Design Bases for Protection Against Natural Phenomena"
- GDC 4, "Environmental and Dynamic Effects Design Bases"
- GDC 12, "Suppression of Reactor Power Oscillations"
- GDC 13, "Instrumentation and Control"
- GDC 19, "Control Room"
- GDC 20, "Protection System Functions"
- GDC 21, "Protection System Reliability and Testability"
- GDC 22, "Protection System Independence"
- GDC 23, "Protection System Failure Modes"
- GDC 24, "Separation of Protection and Control Systems"
- GDC 25, "Protection System Requirements for Reactivity Control Malfunctions"
- GDC 29, "Protection Against Anticipated Operational Occurrences"

The following regulatory guides and industry standards provide information, recommendations, and guidance. In addition, they serve as acceptable bases for implementing the above-noted requirements for the hardware and software features of safety-related digital systems.

- Institute of Electrical and Electronics Engineers (IEEE) Standard (Std) 7-4.3.2-1993, "American National Standard Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations," as endorsed by Regulatory Guide (RG) 1.152, "Criteria for Digital Computers in Safety Systems of Nuclear Power Plants"

- IEEE Std 323-1983, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," as endorsed by RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants"

- American National Standards Institute (ANSI)/IEEE Std 338-1987, "IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems," as endorsed by RG 1.118, "Periodic Testing of Electric Power and Protection Systems"

- IEEE Std 344-1987, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations"

- ANSI/IEEE Std 379-2000, "IEEE Standard Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems," as endorsed by RG 1.53, "Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems"

- IEEE Std 384-1992, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits," as endorsed by RG 1.75, "Physical Independence of Electric Systems"
- IEEE Std 603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations," as endorsed by RG 1.153, "Criteria for Safety Systems"
- IEEE Std 730-1989, "IEEE Standard for Software Quality Assurance Plans," as referenced in BTP HICB-14, "Guidance on Software Reviews for Digital Computer-Based Instrumentation and Control Systems"
- IEEE Std 828-1990, "IEEE Standard for Software Configuration Management Plans," as endorsed by RG 1.169, "Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants"
- IEEE Std 829-1983, "IEEE Standard for Software Test Documentation," as endorsed by RG 1.170, "Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants"
- IEEE Std 830-1993, "IEEE Recommended Practice for Software Requirements," as endorsed by RG 1.172, "Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants"
- IEEE Std 1012-1986, "IEEE Standard for Software Verification and Validation Plans," as endorsed by RG 1.168, "Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants"
- IEEE Std 1016-1987, "IEEE Recommended Practice for Software Design Descriptions"
- IEEE Std 1028-1988, "IEEE Standard for Software Reviews and Audits," as endorsed by RG 1.168
- ANSI/IEEE Std 1042-1987, "IEEE Guide to Software Configuration Management," as endorsed by RG 1.169
- IEEE Std 1074-1995, "IEEE Standard for Developing Software Life Cycle Processes," as endorsed by RG 1.173, "Developing Software Life Cycle Processes for Digital Computer Systems Used in Safety Systems of Nuclear Power Plants"
- Military Standard (MIL-STD)-461C, "Electromagnetic Emission and Susceptibility Requirements for the Control of Electromagnetic Interference"
- International Electrotechnical Commission (IEC) Standard 880-1996, "Software for Computers in the Safety Systems of Nuclear Power Stations," as referenced in the SRP

- American Society of Mechanical Engineers (ASME) NQA-2a-1990, Part 2.7, "Quality Assurance Requirements of Computer Systems for Nuclear Facility Applications," as referenced in the SRP

- Electric Power Research Institute (EPRI) Topical Report (TR)-107330, "Generic Requirements Specification for Qualifying a Commercially Available PLC [Programmable Logic Controller] for Safety-Related Applications in Nuclear Power Plants," approved by the NRC on July 30, 1998

- EPRI TR-102323-R1, "Guidelines for Electromagnetic Interference Testing in Power Plants," approved by the NRC on April 16, 1996

- EPRI TR-106439, "Guideline on Evaluation and Acceptance of Commercial Grade Digital Equipment for Nuclear Safety Applications," approved by the NRC in April 1997

7.1.2 Basis and Method of Review

The AP1000 I&C system uses a microprocessor-based, distributed digital system to perform plant protection functions and safety monitoring, as well as plant control functions. To ensure that the digital I&C system is implemented properly, the staff considered existing regulatory requirements, guides, and standards identified in the SRP, as well as additional standards applicable to digital systems. The use of digital computer technology in protection and control systems raises the possibility that software for these computer systems could be vulnerable to programming errors. Such errors could lead to safety-significant, common-mode failures. The primary factors for defense against common-mode failures are quality and diversity in the digital I&C system design. Sections 7.1.3, 7.1.4, 7.1.5, and 7.1.6 of this report discuss these factors in more detail.

The AP1000 uses passive safety systems that rely on natural forces, such as density differences, gravity, and stored energy, to provide water for core and containment cooling. The active AP1000 systems are not classified as safety-related. Therefore, credit is not taken for these active systems in the design-basis accident analyses described in DCD Tier 2, Chapter 15, "Accident Analysis," unless their operation makes the consequences of an accident more limiting. The non-safety-related active systems in the AP1000 provide defense-in-depth functions and supplement the capability of the safety-related passive systems.

This report also describes certain items that are included in DCD Tier 1, Information. Tier 1, Information provides the design description; the inspections, tests, analyses, and acceptance criteria (ITAAC); and the interface requirements for design certification. Chapter 14 of this report discusses the Tier 1, Information development process, its bases, and its acceptability. Chapter 7 of this report discusses only those areas that relate specifically to the certified design process for the I&C systems, in addition to specific I&C design characteristics. References to previously reviewed plant designs and topical reports are provided where applicable.

7.1.3 General Findings

DCD Tier 2, Chapter 7, for the AP1000 design provides for the use of either the I&C systems similar to the AP600 design, or the Common Qualified Platform design, as described in Westinghouse Topical Report CENPD-396-P, Revision 1, "Common Qualified Platform," issued in May 2000.

7.1.3.1 Compliance with SRP Criteria

The acceptance criteria listed in SRP Table 7-1 identify the Commission's regulations and industry codes and standards applicable to I&C system design. The SRP provides additional review guidance and acceptance criteria that are not provided in the specified requirements, standards, and other references. SRP Table 7-1 provides a cross-reference to the DCD sections that address the applicable standards and criteria. In general, the applicant has committed to meet the SRP guidance with few exceptions. These exceptions are noted in DCD Tier 2, Sections 1.9, "Compliance with Regulatory Criteria," and 3.1, "Conformance with Nuclear Regulatory Commission General Design Criteria," as well as the applicable sections of this report. DCD Tier 1 includes the most important aspects of those criteria that are required to be certified by rulemaking. Section 7.1.4 of this report discusses this information.

The requirements of Appendix A to 10 CFR Part 50 contain the GDC applicable to I&C systems. DCD Tier 2, Section 3.1 discusses, in general terms, compliance with the requirements of the GDC, and references other DCD chapters for specifics.

Appendix 7-B, "General Agenda, Station Site Visits," to Chapter 7 of the SRP provides a general agenda for the station site visit related to the I&C systems, including verification of layouts, separation and isolation, test features, and potential for damage due to fire, flooding, or other environmental effects. Since the design certification for the AP1000 design will be issued under 10 CFR Part 52 before a construction site is selected, this SRP review item cannot be completed at this stage of the review. The inspection tasks, identified in Appendix 7-B to Chapter 7 of the SRP as necessary for design certification, will be addressed through the ITAAC process and the commitments to preoperational tests described in DCD Tier 2, Chapter 14. The review described in Appendix 7-B to SRP Chapter 7 will be accomplished as part of the testing and inspections done by those combined license (COL) applicants referencing the AP1000 certified design.

7.1.3.2 Compliance with Industry Standards

DCD Tier 2 references IEEE Std 603-1991 for the design of the AP1000 I&C systems. Title 10, Section 50.55a(h), of the Code of Federal Regulations (10 CFR 50.55a(h)) requires that protection systems meet the requirements of IEEE Std 603-1991. DCD Tier 2, Section 7.1.4.2, "Conformance with Industry Standards," lists other IEEE standards which are acceptable to the NRC staff and have been endorsed in regulatory guides or included in the SRP. The DCD further references Westinghouse Topical Report CENPD-396-P for details on the design of the PMS. Section 4 of Topical Report CENPD-396-P discusses the Common Qualified Platform's compliance to the industry codes and standards. The staff regards the application of acceptable standards throughout the I&C system design and production process as an important element of the quality demonstration. The application for the design certification must contain a level of information sufficient to enable the staff to make its safety determination. The staff concludes that an explicit commitment to industry hardware- and software-related standards is important in achieving high quality in the digital I&C system product.

7.1.3.3 Compliance with 10 CFR Part 52

Since the AP1000 has been submitted for design certification, the requirements of 10 CFR Part 52 apply in addition to those of 10 CFR Part 50. Title 10, Part 52, of the Code of Federal Regulations requires a level of design detail beyond a simple commitment to conformance with the existing requirements. The requirement of 10 CFR 52.47(a)(2) specifies the following:

> The application must contain a level of design information sufficient to enable the Commission to judge the applicant's proposed means of assuring that construction conforms to the design and to reach a final conclusion on all safety questions associated with the design before the certification is granted. The information submitted for a design certification must include performance requirements and design information sufficiently detailed to permit the preparation of acceptance and inspection requirements by the NRC, and procurement specifications and construction and installation specifications by an applicant. The Commission will require, prior to design certification, that information normally contained in certain procurement specifications and construction and installation specifications be completed and available for audit if such information is necessary for the Commission to make its safety determination.

The requirement of 10 CFR 52.47(b)(1) also states that "this rule must provide an essentially complete nuclear power plant design except for site-specific elements..". The following sections of this report describe the information provided by the applicant, as well as the staff's conclusions concerning conformance with the SRP criteria; additional criteria necessary to address digital I&C technology; and the above requirements of 10 CFR Part 52.

The applicant has not completed developing the design of the AP1000 digital I&C system. Therefore, the staff's safety determination under 10 CFR Part 52 will rely on a satisfactory demonstration by the COL applicant that the digital I&C system design development process, as documented in the DCD, will ensure that the digital I&C system, as designed, will satisfactorily accomplish its safety functions. The staff will then confirm the effectiveness of the COL applicant's implementation of this process through audits of the ITAAC implementation at various phases of the design development. The design acceptance criteria (DAC) approach enables the staff to conclude whether the I&C system design is implemented in accordance with the design process; the associated ITAAC will verify that the system will be operated in accordance with the design certification.

7.1.4 Tier 1, Material

In an August 28, 2000, letter, as supplemented by a second letter dated February 13, 2002, the applicant requested the staff to review the acceptability of its proposed use of DAC to support the development of the design certification application for the AP1000 design. As a result of its preapplication review, in SECY-02-0059, "Use of Design Acceptance Criteria for the AP1000 Standard Plant Design," dated April 1, 2002, the staff concluded that the use of DAC in the I&C and control room (human factors engineering) areas is acceptable because these areas are characterized by a rapidly changing technology. If the NRC were to require completion of the design at the design certification stage, the design for these areas may become obsolete by the time a plant is constructed. The staff concludes, in SECY-02-0059, that it is acceptable to use the DAC approach in the I&C, control room (human factor engineering), and piping design areas, contingent upon the ability of the applicant and the staff to agree on adequate DAC during the design certification review. Although recognizing the DAC approach as a possible substitute for required design details, the staff concluded that the use of DAC, instead of detailed design information, should be limited. The DAC approach should be restricted to those design areas affected by rapidly changing technologies, or design areas for which as-built, or as-procured, information is not available.

The concept of DAC would enable the staff to make a final safety determination, subject only to satisfactory design implementation and verification by the COL applicant, through appropriate use of ITAAC. The staff defined DAC as a set of prescribed limits, parameters, procedures, and attributes upon which the NRC relies, in a limited number of technical areas, in making a final safety determination to support a design certification. The acceptance criteria for DAC become the acceptance criteria for ITAAC, which are part of the design certification and referred to as Tier 1, Material (or Tier 1, Information).

In Volume 1 of the DCD, the applicant provided the Tier 1, Information. The Tier 1, Information contains the design descriptions and associated ITAAC. The applicant organized its AP1000 Tier 1, Information in a manner similar to that used for the evolutionary designs (advanced boiling-water reactor and System 80+) and the AP600 design. The I&C systems Tier 1, Information proposed by the applicant for AP1000, including system descriptions and ITAAC, is similar to AP600 Tier 1, Information. DCD Tier 1, Section 2.5 identifies the I&C systems design description and ITAAC, which include the following plant systems. Specific section numbers for each of these systems are provided in parentheses.

- diverse actuation system (2.5.1)
- protection and safety monitoring system (2.5.2)
- plant control system (2.5.3)
- data display and processing system (2.5.4)
- in-core instrumentation system (2.5.5)
- special monitoring system (2.5.6)
- operation and control centers system (2.5.7)
- radiation monitoring system (2.5.8)
- seismic monitoring system (2.5.9)
- main turbine control and diagnostic system (2.5.10)

Section 14.3 of this report addresses the staff's review of Tier 1, Information.

7.1.5 Instrumentation & Control System Architecture

The AP1000 I&C systems are comprised of the following major systems:

- protection and safety monitoring system
- plant control system
- operation and control centers system
- data and display processing system
- in-core instrumentation system
- special monitoring system
- diverse actuation system

The PMS monitors the plant processes, using a variety of sensors; performs calculations, comparisons, and logic functions based on those sensor inputs; and actuates a variety of equipment. Most of the time, the PMS operates automatically without input from plant personnel, except for system startup, testing, calibration, and maintenance. The PMS is used to operate safety-related systems and components and includes the following major components:

- plant protection subsystems
- engineered safety features coincidence logic
- engineered safety features actuation subsystems
- reactor trip switchgear
- qualified data processing subsystems
- main control room and remote shutdown workstation multiplexers
- sensors
- communication features
- maintenance, test, and bypass features

The plant control system (PLS) controls and coordinates the plant systems during startup, ascent to power, power operation, and shutdown conditions; integrates the automatic and manual control of the reactor, reactor coolant, and various reactor support processes for required normal and off-normal conditions; controls the non-safety-related decay heat removal systems during shutdown; and permits the operator to control plant components from the main control room (MCR) or remote shutdown workstation. The PLS accomplishes these functions through use of the following features:

- rod control
- pressurizer pressure and level control
- steam generator water level control
- steam dump (turbine bypass) control
- rapid power reduction

The operation and control centers system (OCS) includes the complete operational scope of the MCR, remote shutdown workstation, technical support center, emergency operations facility, local control stations, and associated workstations for these centers.

The data and display processing system (DDS) comprises the equipment used for processing data that result in non-Class 1E alarms and displays for both normal and emergency plant operations.

The in-core instrumentation system (IIS) provides the flux map of the reactor core and in-core thermocouple signals for postaccident monitoring.

The special monitoring system (SMS) monitors the loose parts of the reactor coolant system.

The diverse actuation system (DAS) provides a backup to the PMS for some specific diverse automatic or manual actuation. In addition, the DAS provides diverse indications to assist in operator manual actions. The DAS is a defense-in-depth system that provides essential protection functions in the event of a postulated common-mode failure of the PMS.

7.1.6 Defense-in-Depth and Diversity Assessment of the AP1000 Protection System

The Westinghouse RESAR-414 standardized design was the first design reviewed by the staff specifically with regard to defense against potential common-mode failures in digital systems. The results of the staff's review of RESAR-414 were published in NUREG-0493, "A Defense-in-Depth and Diversity Assessment of the RESAR-414 Integrated Protection System," issued in March 1979. NUREG-0493 discussed common-mode failures and different types of diversity, and presented a method for assessing the defense-in-depth of the design.

The staff described concerns with common-mode failures and other digital system design issues in SECY-91-292, "Digital Computer Systems for Advanced Light Water Reactors," dated September 16, 1991. SECY-91-292 describes how common-mode failures could defeat the redundancy achieved by the hardware architectural structure, but could also result in the loss of more than one echelon of defense-in-depth provided by the monitoring, control, reactor protection, and engineered safety functions performed by the digital I&C systems. Quality and diversity are the two principal factors for defense against common-mode/common-cause failures. Maintaining high quality will increase the reliability of both individual components and complete systems. Diversity in assigned functions (for both equipment and human activities), equipment, hardware, and software can reduce the consequences of a common-mode failure.

The modules in the AP1000 PMS are to be implemented by microprocessor-based designs with identical or similar hardware and software used in all four divisions. Because of this similarity, the concerns expressed in NUREG-0493 and SECY-91-292 apply directly to the PMS.

Several regulations and industry standards address the need for defense against potential common-mode failures:

- GDC 22 requires that "design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function."

- 10 CFR 50.55a(h) (IEEE Std 603-1991) requires that "equipment, not subject to failure caused by the same credible event, shall be provided to detect the event...."

- IEEE Std 379-1988 states that "certain common-cause failures shall be treated as single failures when conducting the single failure analysis. Such failures can be in dissimilar components and can have dissimilar failure modes."

In addition, 10 CFR 50.62 addresses common-mode failure issues concerning mitigation of anticipated transients without scram (ATWS).

Common-cause failures not subject to single-failure analysis include those that can result from external environmental effects, design deficiencies, manufacturing errors, and operator errors. Design qualification and quality assurance programs are intended to afford protection from external environmental effects, design deficiencies, and manufacturing errors. Personnel training, proper control room design, and operating and maintenance procedures are intended to afford protection from maintenance and operator errors.

NUREG-0493 discusses several different types of diversity, each of which offers certain protection against common-mode failures. For example, neutron flux and reactor pressure are diverse signals for initiation of reactor scram. Equipment diversity includes using different kinds of equipment to perform a function. The use of relay versus solid-state logic in the I&C system is an example of equipment diversity described in NUREG-0493. It is difficult to define how much improvement in safety results from a given kind or degree of diversity. For microprocessor design, this is especially difficult because there is no industry consensus on a method to quantify software reliability and/or availability.

As stated above, the staff considers the two principal factors for defense against common-mode failures to be quality and diversity. Section 7.2.8 of this report addresses the quality in the design process aspects of the AP1000 I&C systems. Quality is achieved, in part, by the use of quality design standards for the hardware and software, and by the I&C system testing to be performed.

The staff's position on I&C system diversity for advanced light-water reactors (ALWRs) is stated in SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor Design," April 2, 1993. This position was approved by the Commission in a staff requirements memorandum (SRM) dated July 21, 1993. The four key points of the SRM are as follows:

1. The applicant shall assess the defense-in-depth and diversity of the proposed I&C system to demonstrate that vulnerabilities to common-mode failures have been adequately addressed.

2. In performing the assessment, the vendor or applicant shall analyze each postulated common-mode failure for each event that is evaluated in the accident analysis section of the Safety Analysis Report using best-estimate methods. The vendor or applicant shall demonstrate adequate diversity within the design for each of these events.

3. If a postulated common-mode failure could disable a safety function, then a diverse means, with a documented basis that the diverse means is unlikely to be subject to the same common-mode failure, shall be required to perform either the same function or a different function. The diverse or different function may be performed by a non-safety system if the system is of sufficient quality to perform the necessary function under the associated event conditions.

4. A set of displays and controls located in the main control room shall be provided for manual system-level actuation of critical safety functions and monitoring of parameters that support the safety functions. The displays and controls shall be independent and diverse from the safety computer system identified in Items 1 and 3 above.

Staff review guidance on this position is included in the SRP Chapter 7, Appendix 7-A, BTP-19, "Guidance for Evaluation of Defense-in-Depth and Diversity in Digital Computer-Based Instrumentation and Control Systems."

In response to the NRC staff's position on I&C system diversity for ALWRs, the applicant submitted WCAP-15775, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report." This report, issued in April 2002, describes the diversity and defense-in-depth features of the AP1000 I&C architecture following the guidelines outlined in BTP-19. The staff finds that the report demonstrates conformance to the acceptance criteria found in BTP-19.

The analysis of the ability of the AP1000 I&C architecture to protect against common-mode failure was done as part of the probabilistic risk assessment (PRA) for the AP1000 design. The PRA analyzed failures of the I&C system architecture, including common-cause failures. The PMS analysis is described in AP1000 PRA, Chapter 26, "Protection and Safety Monitoring System," and the PLS is described in PRA, Chapter 28, "Plant Control System." Chapter 27, "Diverse Actuation System," of AP1000 PRA, describes the analyses of the diverse, non-safety-related DAS.

In addition, the applicant submitted WCAP-13793, "AP600 System/Event Matrix," issued in 1994, which describes how the AP600 systems are used to protect the reactor during different events. For each event, WCAP-13793 lists different safety- and non-safety-related systems which are used to protect the reactor, and identifies systems that provide reactor shutdown, reactor coolant system (RCS) makeup, core decay heat removal, and containment cooling. This report also includes the type of actuation and electrical power requirements for each system. The purpose of this document is to demonstrate that multiple levels of defense exist for each type of event. The DAS has been credited with providing reactor protection functions in every event analyzed. Although WCAP-13793 is an AP600 document, the AP1000 systems which are used to protect the reactor, shut down the reactor, provide RCS makeup, provide core decay heat removal, and provide containment cooling are the same as those in AP600. Therefore, the staff finds that the analyses described in WCAP-13793 are applicable to AP1000.

Based on its review, the staff finds that the applicant has assessed the defense-in-depth and diversity of the AP1000 I&C system and has demonstrated that vulnerabilities to common-mode failures have been adequately addressed. The applicant has analyzed each postulated common-mode failure for each event that is evaluated in the accident analysis section of the DCD, and has addressed the diversity requirements within the design for each of these events. The DAS, as proposed, performs the same functions as the PMS when a postulated common-mode failure disables the PMS protection functions. In addition, the DAS, as proposed, includes displays, independent and diverse from the PMS, that can support any necessary manual actions in the event that a postulated common-mode failure disables the PMS. Therefore, the staff concludes that the proposed design satisfies the Commission's position on I&C system diversity. Section 7.7.2 of this report further discusses the evaluation of the DAS.

7.1.7 Commercial-Grade Item Dedication

Digital components to be used in safety systems must be qualified for their intended application by either a 10 CFR Part 50, Appendix B, quality assurance program, or by dedicating the item for use in the safety system, as defined in 10 CFR Part 21. The NRC approved EPRI TR-106439, "Guideline on Evaluation and Acceptance of Commercial Grade Digital Equipment for Nuclear Safety Applications," in 1997. The section of EPRI TR-106439 entitled, "Requirements on the Dedicator," states the following:

> The process of performing commercial-grade item procurement and dedication activities is itself a safety-related process and, as such, must be controlled and performed in accordance with a quality assurance (QA) program that meets the requirements of 10 CFR [Part] 50[,] Appendix B. This applies to the dedicating entity whether it is the utility or a third-party dedicator.

The applicant is an approved 10 CFR Part 50, Appendix B, supplier. The staff does not attempt in this review to renew the applicant's status as an approved 10 CFR Part 50, Appendix B, supplier. During the review of the Common Qualified Platform, the staff audited a sampling of manuals for commercial-grade dedication activities. On the basis of the audit, the staff finds that the procedures and processes in the manuals correspond to the requirements of IEEE Std 7-4.3.2-1993 and the guidance of EPRI TR-106439 and, therefore, provide an acceptable program for the dedication of commercial-grade items. During the review of the Common Qualified Platform, the staff reviewed the reports of the dedication of commercial-grade AC160 hardware and software for use in nuclear safety systems. On the basis of that review, the staff concludes that the AC160 programmable logic controllers system meets the requirements set forth in BTP HICB-18, "Guidance on the Use of Programmable Logic Controllers in Digital

Computer-Based Instrumentation and Control Systems," and follows the guidance in EPRI TR-106439. Therefore, this system is acceptable for use in nuclear power plants.

On the basis of the staff's review of the Common Qualified Platform flat panel display system (FPDS), the staff concludes that the applicant has acceptably dedicated the commercial-grade QNX4, *Version 4.25b, and Photon microGUI, Version 1.13b, in accordance with the guidance in* EPRI TR-106439 for use as the operating system and display builder for the FPDS in the Common Qualified Platform.

The commercial dedication issue includes the qualification of the automated tools and design support software. The staff also expects the I&C system developer to verify that the tools function correctly and to verify the quality of the tools used in the design.

The staff's concern regarding communication by the suppliers to the end user of errors discovered in the suppliers' tools or software is an issue related to commercial dedication. This issue is similar to the 10 CFR Part 21 defect reporting required for Class 1E equipment vendors. The COL applicant referencing the AP1000 commercial dedication program shall commit to seek NRC review and approval before implementing any change to the software commercial dedication process of the safety-related system. Any request for changes should either be specifically described in the COL application or submitted for license amendment after issuance of the license. DCD Tier 2, Section 7.1.6, "Combined License Information," addresses this issue generically by stating that "Combined License applicants referencing the AP1000 certified design will provide resolution for generic open items and plant-specific action items resulting from NRC review of the I&C platform." This is COL Action Item 7.1.7-1.

7.2 Reactor Trip System

7.2.1 System Description

The reactor trip system (RTS) performs the reactor scram function by interrupting electrical power to the rod control system and allowing the control rods to fall by gravity into the reactor core. The RTS includes power sources, sensors, communication links, software/firmware, *initiation circuits, logic matrices, bypasses, interlocks, switchgear, actuation logic, and actuated* devices that are required to initiate a reactor trip. The RTS is designed to automatically initiate the rapid insertion of the control rods of the reactivity control system to ensure that the specified acceptable fuel design limits are not exceeded. Manual initiation is also provided as a backup to automatic initiation. The RTS also provides status information to the operator, and status and control signals to other systems and annunciators. The RTS, which is qualified as a Class 1E safety system and is environmentally and seismically qualified, provides the following reactor trip functions:

- nuclear startup trips
  - source range high neutron flux trip
  - intermediate range high neutron flux trip

  - power range high neutron flux trip (low setpoint)

- nuclear overpower trips

  - power range high neutron flux trip (high setpoint)
  - power range high positive flux rate trip

- core heat removal trips

  - overtemperature delta T trip
  - overpower delta T trip
  - low pressurizer pressure trip
  - low reactor coolant flow trip
  - reactor coolant pump underspeed trip
  - high reactor coolant pump bearing water temperature trip

- primary system overpressure trips

  - high pressurizer pressure trip
  - high pressurizer water level trip

- loss of heat sink trip

  - low steam generator water level trip (in any steam generator)

- feedwater isolation trip

  - high-2 steam generator water level in any steam generator trip

- automatic depressurization system actuation trip

- core makeup tank injection trip

- safeguard actuation trip

- manual trip

The RTS automatically initiates rapid insertion of the control rods to scram the reactor when warranted by any one of the predetermined conditions listed above. The reactor trip is initiated by means of four redundant divisions of sensor channels, trip logic, and trip actuators, except for the manual scram function, which is accomplished from the MCR by two redundant switches. The RTS is a four division system where each parameter is monitored by four sensor channels, one in each division. Each division of sensor channels is powered from the respective Class 1E battery-backed power supply. The coincidence logic (two-out-of-four) requires the two tripped signal inputs from the same parameter. The RTS will periodically be tested during plant operation as defined by the technical specifications (TSs) in DCD Tier 2, Chapter 16.

Complete electrical and physical separation is maintained between the four RTS divisions to meet the criteria of IEEE Std 603-1991. This requirement will be verified during the implementation of the ITAAC, as defined in DCD Tier 1, Section 2.5.2. A trip of any sensor or logic channel is annunciated and causes that channel to lock in the trip mode until manually reset. The RTS is fail safe in that a loss of power to a channel will result in that channel going to the tripped condition. Other failures, such as a break in a communications link, are detected by the self-diagnostics of the individual microprocessor that will place the output in the tripped state.

The staff reviewed the RTS for conformance to 10 CFR 50.55a(h)(3) (which requires conformance to the requirements of IEEE Std 603-1991 and correction sheet dated January 30, 1995). IEEE Std 603-1991 includes requirements for meeting the single-failure criterion, independence, control and protection system interaction (isolation), testing, bypass and bypass indication (including removal of bypass), and manual initiation. The staff concludes that the RTS description and drawings in the DCD establish a clear commitment to the above requirements of IEEE Std 603-1991 and 10 CFR 50.55a(h)(3).

7.2.2 Protection and Safety Monitoring System Description

The PMS provides detection of off-normal conditions and actuation of appropriate safety-related functions necessary to achieve and maintain the plant in a safe-shutdown condition. The PMS controls safety-related components in the plant that are operated from the MCR or remote shutdown workstation. In addition, the PMS provides the equipment necessary to monitor the plant safety-related functions during and following an accident, as required by RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."

The PMS for the AP1000 implements its functions by software logic installed in programmable digital devices (data processors). Plant data and other signals are exchanged between data processors by means of isolated data links and data highways. The functions of the PMS are implemented in separate processor-based subsystems. Each subsystem is located on an independent computer bus to prevent propagation of failures and to enhance availability. Each subsystem is implemented in a separate card chassis. Subsystem independence is maintained by the following design features:

- separate direct current (dc) power sources for redundant subsystems with output protection to prevent interaction between redundant subsystems upon failure of a subsystem
- separate input or output circuitry to maintain independence at the subsystem interfaces

- deadman signals, which include a device, circuit, or function that forces a predefined operating condition on the cessation of a normal dynamic input parameter to improve the reliability of hard-wired data that cross the subsystem interface

- optical coupling or resistor buffering between two subsystems or between a subsystem and an input/output module

WCAP-13382, "AP600 Instrumentation and Control Hardware Description," issued in May 1992, and WCAP-14080, "AP600 Instrumentation and Control Software Architecture and Operation Description," issued in June 1994, provide a detailed description of the AP600 PMS design. These two topical reports were accepted by the staff under the AP600 design certification. The staff found that these reports conform to the standards and guidelines discussed in Chapter 7 of the SRP. Since the I&C system architecture, hardware, and software of the AP1000 PMS, as well as the systems, equipment, and components that the PMS controls and monitors, are the same as those in the AP600, the staff finds that these two topical reports are applicable to the AP1000 design.

Alternatively, the AP1000 PMS may be based on the Common Qualified Platform design as described in Topical Report CENPD-396-P. Sections 7.2.3 and 7.2.4 of this safety evaluation report address the evaluation of the Common Qualified Platform design. The PMS initiates an automatic reactor trip and automatic actuation of ESFs. The PMS two-out-of-four initiation logic reverts to a two-out-of-three coincidence logic if one of the four channels is bypassed. The PMS (using the Common Qualified Platform design) does not allow simultaneous bypass of two redundant channels. The PMS has redundant divisions of safety-related postaccident parameter display. Each PMS division is powered from its respective Class 1E dc and uninterruptible power supply (UPS) division. The MCR provides dedicated fixed position controls and indications for the reactor trip and the ESF functions.

Reliability of the PMS is provided by the following features:

- The reactor trip functions are divided into two subsystems.

- The engineered safety feature functions are processed by two microprocessor-based subsystems that are functionally identical in both hardware and software.

- Continuous monitoring and failure detection/alarm are provided.

- The PMS equipment is designed to accommodate a loss of normal heating, ventilation, and air conditioning (HVAC). PMS equipment is protected by the passive heat sinks upon failure or degradation of the active HVAC.

- The PMS equipment is under the design reliability assurance program.

7.2.3 Common Qualified Platform Design and COL Action Items

Topical Report CENPD-396-P describes the detailed design of the Common Qualified Platform. The staff issued safety evaluations approving the Common Qualified Platform in August 11, 2000, June 22, 2001, and April 2, 2003. The Common Qualified Platform is designed as a standard digital I&C platform with a modular structure for nuclear safety-related applications, including component replacement and complete system upgrades. The Common Qualified Platform is applicable to postaccident monitoring systems, core protection calculator systems, reactor protection systems, plant protection systems, engineered safeguards systems, and other nuclear safety-related applications. The Common Qualified Platform is a computer system consisting of a set of commercial-grade hardware and previously developed software components dedicated and qualified for use in nuclear power plants.

On August 11, 2000, the NRC staff issued a safety evaluation report (SER) entitled, "Acceptance for Referencing of Topical Report CENPD-396-P, Revision 1, 'Common Qualified Platform.'" Section 6 of that SER identified 14 plant-specific action items (PSAIs). In response to the staff's request for additional information (RAI) 420.028, the applicant addressed each of these 14 PSAIs. The ITAAC process will verify the design requirements of these items. The ITAAC process is documented in DCD Tier 1, Section 2.5.2. The resolution of each of these PSAIs is addressed as follows:

PSAI 6.1: Each licensee implementing a specific application based upon the Common Qualified Platform must assess the suitability of the S600 I/O modules to be used in the design against its plant-specific I/O requirements.

Resolution: The quality assurance program described in DCD Tier 2, Chapter 17, for procurement, fabrication, installation, construction, and testing of systems and components in the facility will cover this issue.

PSAI 6.2: A hardware user interface that replicates existing plant capabilities for an application may be chosen by a licensee as an alternative to the FPDS. The review of the implementation of such a hardware user interface would be a plant-specific action item.

Resolution: The applicant stated that AP1000 safety systems will use the FPDS as developed by the applicant. An alternative hardware interface will not be used.

PSAI 6.3: If a licensee installs a Common Qualified Platform application that encompasses the implementation of the FPDS, the use of the FPDS must be treated in the plant-specific failure modes and effects analysis (FMEAs).

Resolution: This item is included in the resolution of PSAI 6.10.

PSAI 6.4: Each licensee implementing a Common Qualified Platform application must verify that its plant environmental data (e.g., temperature, humidity, seismic, and electromagnetic compatibility) for the locations in which the Common Qualified

Platform equipment is to be installed are enveloped by the environment considered for the Common Qualified Platform qualification testing. The specific equipment configuration to be installed should be similar to that of the Common Qualified Platform equipment used for the test.

Resolution: DCD Tier 1, Section 2.5.2, item 4 covers the temperature and humidity qualification of the PMS equipment; DCD Tier 1, Section 2.5.2, item 2 covers the seismic qualification; and DCD Tier 1, Section 2.5.2, item 3 covers the electromagnetic interference/radio frequency interference qualification. Through these ITAAC verification processes, the COL applicant is responsible to verify that its plant-specific environmental conditions, for all modes of operation for all locations in which the Common Qualified Platform equipment is to be installed, are within those covered by Topical Report CENPD-396-P. COL applicants referencing the AP1000 certified design will provide resolution for generic open items and plant-specific action items resulting from the NRC review of the I&C platform. This is COL Action Item 7.2.3-1.

PSAI 6.5: *The software program manual specifies plans that will provide a quality software* life cycle process. These plans commit to documentation of life cycle activities that will permit the staff to review the implementation of the life cycle process for application on a plant-specific basis.

Resolution: Item 11 in DCD Tier 1, Section 2.5.2, covers the software life cycle process. The evaluation of the Common Qualified Platform's life cycle process is documented in the August 11, 2000, SER referenced above.

PSAI 6.6: When implementing a Common Qualified Platform safety system, the licensee must review the application timing analysis and validation tests for that Common Qualified Platform system to verify that it satisfies the plant-specific requirements for accuracy and response time presented in the accident analysis in Chapter 15 of the safety analysis report.

Resolution: The accuracy and response time of the AP1000 safety systems will be commensurate with the Chapter 15 safety analysis. The COL applicant is responsible for the setpoint analysis. The setpoint analysis shall be performed by the COL applicant, as defined in DCD Tier 1, Section 2.5.2, item 10, and DCD Tier 2, Section 7.1.6. This is COL Action Item 7.2.7-1, as discussed in Section 7.2.7 of this report.

PSAI 6.7: The operator's module and the maintenance and test panel provide the human machine interface for the Common Qualified Platform. Both will include display and diagnostic capabilities unavailable in the existing analog safety systems. The human factor considerations for specific applications of the Common Qualified Platform will be evaluated on a plant-specific basis.

Resolution: The human factors program is the responsibility of the COL applicant and is covered by DCD Tier 1, Section 3.2, and DCD Tier 2, Section 18.2.6, "Combined License Information." This is COL Action Item 18.2.4-1, as discussed in Chapter 18 of this report.

PSAI 6.8: If the licensee installs a Common Qualified Platform postaccident monitoring system (PAMS), core protection calculator, or digital plant protection systems (DPPS), the licensee must verify on a plant-specific basis that the new system provides the same functionality as the system that is being replaced, in addition to meeting the functionality requirements applicable to those systems.

Resolution: The AP1000 is a new plant safety system installation; therefore, this action is not applicable.

PSAI 6.9: Modifications to plant procedures and/or TSs due to the installation of a Common Qualified Platform safety system will be reviewed by the staff on a plant-specific basis. Each licensee installing a Common Qualified Platform safety system shall submit its plant-specific request for license amendment with attendant justification.

Resolution: The AP1000 is a new plant safety system installation. The COL applicant will be responsible for plant procedures, as discussed in DCD Tier 2, Section 13.5.1. This is COL Action Item 13.5.1-1, as discussed in Section 13.5.1 of this report.

PSAI 6.10: A licensee implementing any Common Qualified Platform applications must prepare its plant-specific model for the design to be implemented and perform the FMEA for that application.

Resolution: COL applicants referencing the AP1000 certified design shall perform an FMEA for each AP1000 safety system. The FMEAs will confirm that no single failure of a safety system component will defeat more than one of the four protective channels, ensuring proper protective action at the system level. DCD Tier 2, Section 7.2.3, "Combined License Information," states that "Combined License applicants referencing the AP1000 certified design will provide an FMEA for the protection and safety monitoring system. The FMEA will include a Software Hazards Analysis." This is COL Action Item 7.2.3-2.

PSAI 6.11: A licensee installing a Common Qualified Platform system shall demonstrate that the plant-specific Common Qualified Platform application complies with the criteria for defense against common-mode failure in digital I&C systems, as well as meets the guidance of BTP HICB-19.

Resolution: The AP1000 design includes both the PMS and the DAS. Both the PMS and DAS provide manual and automatic protective functions. The design features of the PMS will be verified by ITAAC in DCD Tier 1, Section 2.5.2; the design features of the DAS will be verified by ITAAC in DCD Tier 1, Section 2.5.1. The completion of the ITAAC process on both the PMS and the DAS will verify the design features and the functional requirements in both systems.

PSAI 6.12: A licensee implementing a Common Qualified Platform digital plant protection system shall define a formal methodology for overall response time testing.

Resolution: A formal methodology will be defined for response time testing of AP1000 safety systems. DCD Tier 1, Section 2.5.2, item 10, discusses this methodology. DCD Tier 2, Section 7.1.6, "Combined License Information," states that the COL applicant will provide a calculation of setpoints for protective functions consistent with the methodology presented in WCAP-14605, "Westinghouse Setpoint Methodology for Protection Systems - AP600," issued in April 1996. It also states that the COL applicant will provide resolution for generic open items and PSAIs resulting from NRC review of the I&C platform which will include a definition of a methodology for overall response time testing. This is COL Action Item 7.2.3-3.

PSAI 6.13: A licensee implementing the Common Qualified Platform system shall analyze the capacity of the shared resources to accommodate the load increase due to sharing.

Resolution: The shared resource issue relates to multiple Common Qualified Platform-based systems using the same resources, such as the AF100 bus or an operator module. An analysis will be performed to ensure that the capacity of shared resources for AP1000 safety systems is commensurate with anticipated loads. This issue will be addressed as part of the design process that is covered by DCD Tier 1, Section 2.5.2, item 11.

PSAI 6.14: The licensee must ascertain that the implementation of the Common Qualified Platform does not render invalid any of the previously accomplished Three Mile Island (TMI) action items.

Resolution: The safety-related instrumentation systems are designed and built to conform to the applicable criteria, codes, and standards concerned with the safe generation of nuclear power. This issue will be addressed as part of the design process that is covered by DCD Tier 1, Section 2.5.2.

7.2.4 Resolution of Common Qualified Platform Generic Open Items

On August 11, 2000, the NRC staff issued an SER regarding Topical Report CENPD-396-P. Section 7 of that SER identified 10 generic open items. The resolution of these generic open items is documented in staff SERs dated June 22, 2001, and April 2, 2003, for closeout of the Common Qualified Platform Open Items related to reports CENPD-396-P, Revision 1, and CE-CES-195, Revision 1, "Software Program Manual for Common Qualified Platform Systems," issued in May 2000.

7.2.5 PMS Design Process Review

SRP Chapter 7, BTP HICB-14, "Guidance on Software Review for Digital Computer-Based I&C Systems," provides guidance for reviewing the design of the safety-related digital I&C system. The staff's acceptance of software for safety system functions is based upon (1) confirmation that the software was developed in accordance with acceptable software development plans, (2) evidence that the plans were followed in an acceptable software life cycle, and (3) evidence that the process produced acceptable design outputs. BTP-HICB-14 specifies certain information with respect to digital I&C design process and implementation which should be reviewed. In response to RAIs 420.001 and 420.023, the applicant submitted WCAP-15927, "Design Process for AP1000 Common Qualified Platform Safety Systems," issued in August 2002, to define the process for system level design, software design and implementation, and hardware design and implementation for the development of the AP1000 protection system. Document CE-CES-195 discusses additional details regarding the Common Qualified Platform software development plans.

The development of the AP1000 protection system (life cycle phases) includes the following phases which occur in the development of application hardware and software:

- conceptual (project definition)
- system definition
- software design
- hardware design
- software implementation
- hardware implementation
- system integration
- installation

The flow of activities is similar to that of a classic "waterfall" development process. These activities may be both iterative and overlapping. Work may commence on a given development phase before preceding phases are complete. Testing activities are also defined as part of the design verification and validation (V&V) process. The testing activities complement the hardware implementation, software implementation, system integration, and installation phases.

The AP1000 PMS can use the Common Qualified Platform to perform safety-related protective functions, as discussed in Sections 7.2.2 and 7.3.1 of this report. The Common Qualified Platform is designed based on industry standards, regulatory requirements, and engineering experience in and knowledge of the types of functions that are required for typical safety system applications. The Common Qualified Platform consists primarily of the ABB AC160 hardware and software product line, including the Advant development tools. The AC160 product line is not developed by the applicant but is developed commercially. It was selected and qualified by the applicant for use in Common Qualified Platform applications by a process of commercial dedication. The Common Qualified Platform also contain products that are not ABB Advant commercial components. These include software and hardware elements that are developed by the applicant specifically for the Common Qualified Platform.

The software program manual (SPM) describes the requirements for the software design and development process, as well as for the use of software in Common Qualified Platform systems. The SPM consists of several basic elements:

- a software safety plan, which identifies the processes that will reasonably ensure that safety-critical software does not have hazards that could jeopardize the health and safety of the public
- a software quality assurance plan, which describes the process and practice of developing and using software, and which addresses standards, conventions, reviews, problem reporting, and other software quality issues
- a V&V program, which describes the method of ensuring correctness of the software
- a software configuration management plan, which describes the method of maintaining the software in an identifiable state at all times
- a software operations and maintenance plan, which describes software practices after delivery to a customer

The SPM also discusses software management, documentation, and other matters related to software design and use.

The SPM has been reviewed by the staff in conjunction with the review of Topical Report CENPD-396-P. In the August 11, 2000, SER on CENPD-396-P, the staff concluded that the SPM specifies plans that will provide a quality software life cycle process, and that these plans commit to documentation of life cycle activities that will permit the staff or others to evaluate the quality of the design features upon which the safety determination will be based. The staff will review the implementation of the life cycle process and the software life cycle process design outputs for specific applications on a plant-specific basis.

In DCD Tier 1, Section 2.5.2, item 11 specifies that the PMS hardware and software is developed using a planned design process which provides for specific design documentation and reviews during the following life cycle stages:

- design requirement phase (may also be referred to as conceptual or project definition phase)
- system definition phase
- hardware and software development phase, which consists of hardware and software design and implementation
- system integration and test phase
- installation phase

An inspection will be performed on the processes used to design the hardware and software. Each process used shall define the organizational responsibilities, activities, and configuration management controls for the following:

- establishment of plans and methodologies
- specification of functional requirements
- documentation and review of hardware and software
- performance of system tests and the documentation of system test results
- performance of installation tests and inspections

In accordance with the AP1000 quality assurance program, administrative control procedures are used to establish software quality assurance and configuration management for process computer software, firmware, and associated software development, computer systems, and documentation. These ensure that the integrity of a process software product is known and preserved throughout its life cycle (from development to retirement). These controls also apply to the development tools and systems used to develop and test process software.

In DCD Tier 2, Section 7.1.7, both CE-CES-195 and WCAP-15927 are designated as Tier 2* documents. Any change to these two documents will require NRC approval. The SPM (CE-CES-195) describes the software design and development process. This generic software-related document discusses the software safety plan, software quality assurance plan, software V&V plan, software configuration management plan, and software operation and maintenance plan. The guidance in WCAP-15927 should be followed when using the Common Qualified Platform to implement a AP1000 plant-specific design application.

7.2.6 Protection Systems Test Intervals and Allowed Outage Time

Sections TS 3.3.1 and 3.3.2 of DCD Tier 2, Chapter 16, refer to WCAP-10271-P-A, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," as the basis for some of the TS completion times. However, WCAP-10271 is based on the use of analog system hardware by the protection system. Many aspects of the functional design are different for the AP1000 digital systems. In response to RAI 630.021, the applicant has not demonstrated the applicability of the generic analyses of WCAP-10271 for the AP1000 protection system. The COL applicant will need to provide detailed plant protection system FMEA and component reliability data to justify the TS completion time. In response to the NRC staff's additional comment, the applicant agreed, by letter dated April 7, 2003, to add a COL action item to perform a plant-specific FMEA for the protection system to determine the TS completion time for inclusion in the plant TS and Sections TS 3.3.1 and TS 3.3.2.

The AP1000 TS for those values that are based on the FMEA will use brackets around the reference value in the "Completion Time" column. This is addressed in DCD Tier 2, Section 7.2.3, which states the following:

> Combined License applicants referencing the AP1000 certified design will provide an FMEA for the protection and safety monitoring system. The FMEA

will include a Software Hazards Analysis. This FMEA will provide the basis for those Technical Specification Completion Times that rely on an FMEA for their basis.

This is COL Action Item 7.2.6-1.

7.2.7 Protection Systems Setpoint Methodology

In DCD Tier 2, Appendix 1A, "Compliance with Regulatory Criteria," the applicant stated that the AP1000 design conforms to RG 1.105, "Instrument Setpoint for Safety-Related Systems." However, no setpoint methodology documentation was provided. In its response to RAI 420.11, dated October 1, 2002, the applicant stated that WCAP-14605 describes the methodology that will be used by the COL applicant to perform the setpoint study. The methodology can be used to perform setpoint studies independent of the hardware used for the protection system. For example, the value used for rack calibration accuracy may change as the result of a platform change; however, the methodology used to account for rack calibration accuracy will not change. Thus, the methodology, but not the setpoint study itself, is independent of the PMS platform. The general requirement for setpoints is that they be established high enough to preclude inadvertent actuation, but low enough to ensure that a proper margin is maintained in the setpoint determination. The staff finds that the Westinghouse setpoint methodology conforms with the guidance provided in BTP-12, "Guidance on Establishing and Maintaining Instrument Setpoints," and therefore is acceptable.

In DCD Tier 2, Chapter 16, Table 3.3.1-1, "Reactor Trip System Instrumentation," and Table 3.3.2-1, "Engineered Safeguards Actuation System Instrumentation," the values specified in brackets in the "Trip Setpoint" column are the DCD Tier 2, Chapter 15 safety analysis values. These values are provided for information only. The actual setpoints will not be established at this time. The COL applicant should provide the plant-specific trip setpoints, based on the specific I&C system design and equipment installed, and should update Tables 3.3.1-1 and 3.3.2-1, accordingly. This is addressed generically in DCD Tier 2, Section 7.1.6, which states that the "Combined License applicants referencing the AP1000 certified design will provide a calculation of setpoints for protective functions consistent with the methodology presented in WCAP-14605." This is COL Action Item 7.2.7-1.

7.2.8 PMS Evaluation Findings and Conclusions

For the PMS design, the applicant has committed to conform to applicable standards and regulatory guides referenced in the DCD. Based on the review of the information regarding relevant regulatory guides and standards in Chapter 7 of the SRP, the staff finds that the requirements of 10 CFR 50.55a(a)(1) and GDC 1 have been met.

Title 10, Section 50.55a(h), of the Code of Federal Regulations (10 CFR 50.55a(h)) specifies that protection systems must meet the requirements of IEEE Std 603-1991. The applicant submitted WCAP-15776, "Safety Criteria for the AP1000 Instrumentation and Control Systems," issued in April 2002, which describes the design bases for the safety system and discusses its conformance to the general functional requirements of IEEE Std 603-1991. The staff has reviewed WCAP-15776 and verified the design description in DCD Tier 2, Chapter 7, and other AP1000 docketed information. The following are the staff's findings with respect to the conformance of the AP1000 design to the requirements found in Section 4, "Safety System Design Basis," of IEEE Std 603-1991:

- Sections 4.1 and 4.2 of IEEE Std 603-1991 require, in part, the identification of the design-basis events applicable to each mode of operation. The AP1000 safety systems are designed to protect the health and safety of the public by limiting the release of radioactive material during Conditions II, III, and IV events. The release of radioactive material is designed to be within acceptable limits, as defined in DCD Tier 2, Chapter 15. The PMS automatically initiates appropriate protective action when a condition monitored by the system reaches a preset level. The safety analyses demonstrate that even under conservative critical conditions for design-basis accidents, the safety system provides confidence that the plant is put into and maintained in a safe state following a Condition II, III, or IV accident. Based on the discussion above, the staff finds that the AP1000 design meets the requirements of Sections 4.1 and 4.2 of IEEE Std 603-1991.

- Section 4.3 of IEEE Std 603-1991 requires permissive conditions. The AP1000 PMS is designed so that protective functions are initiated and accomplished during various reactor operating modes. The following specific design bases apply:

  - Where operating requirements necessitate automatic or manual block of a protective function, the block is automatically removed whenever the appropriate permissive conditions are not met. Hardware and software used to achieve automatic removal of the block of a protective function are part of the PMS and, as such, are designed in accordance with the same criteria as the protective function.

  - A block of a protective function is automatically cleared when the protective function is required to function.

  Therefore, the staff finds that the AP1000 design satisfies this requirement of Section 4.3 of IEEE Std 603-1991.

- Section 4.4 of IEEE Std 603-1991 requires the definition of protective system variables and their range and rate of changes. DCD Tier 2, Sections 7.2 and 7.3 describe the variables required to be monitored for protective action and their ranges and rates of change. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.4 of IEEE Std 603-1991.

- Section 4.5 of IEEE Std 603-1991 requires a means to permit manual actions. In the AP1000 design, means are provided in the MCR for manual initiation of protective functions at the system level. The manual controls are a backup to the automatic protection provided by the PMS. Manual actuation relies on minimum equipment and, once initiated, proceeds to completion unless the operator deliberately intervenes. Failure in the automatic initiation portion of a system-level function does not prevent the manual initiation of the function. The AP1000 human system interface design includes a minimum inventory of dedicated or fixed-position displays and controls. The fixed-position displays and alarms are quickly and easily retrievable. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.5 of IEEE Std 603-1991.

- Section 4.6 of IEEE Std 603-1991 requires the identification of the minimum number and location of spatial dependence variables. In the AP1000 design, thermowell-mounted resistance temperature detectors (RTDs) installed in each reactor coolant loop provide the hot- and cold-leg temperature signals to the PMS. Three thermowells in each hot leg are mounted 49 °C (120 °F) apart in the cross-sectional plane of the piping to obtain a representative temperature sample. The hot-leg temperature streaming effect and the variability of temperature measurements as a function of thermal power lead to this hot-leg thermowell arrangement. The PMS averages these signals using electronic weighting average methods. The cold-leg RTDs are located downstream of the reactor coolant pump (RCP). The pump provides mixing of the coolant. No special arrangement is required. Radial neutron flux is not a spatially dependent concern because of core radial symmetry. Ex-core detectors furnish axially dependent information to the overtemperature and overpower calculators. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.6 of IEEE Std 603-1991.

- Section 4.7 of IEEE Std 603-1991 requires, in part, that the range of transient and steady-state conditions be identified for the energy supply and the environment during normal, abnormal, and accident conditions under which the system must perform. The AP1000 equipment is environmentally qualified to meet the accident conditions through which it operates to mitigate the consequences of the accident. Equipment is seismically qualified to meet safe-shutdown earthquake levels. The safety system is powered by Class 1E dc and a UPS system. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.7 of IEEE Std 603-1991.

- Section 4.8 of IEEE Std 603-1991 requires, in part, the identification of conditions having the potential for causing functional degradation of safety system performance and the proposed protective action. DCD Tier 2 specifies that the AP1000 design has the ability to initiate and accomplish protective functions during and following natural phenomena such as earthquakes, tornadoes, hurricanes, floods, and winds. Accordingly, plant safety is provided despite degraded conditions caused by internal events such as fire, flooding, explosions, missiles, electrical faults, and pipe whip. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.8 of IEEE Std 603-1991.

- Section 4.9 of IEEE Std 603-1991 requires the identification of the methods used to determine that the reliability of the safety system design is appropriate for each such design. In addition, it requires the identification of the methods used to verify that any qualitative or quantitative reliability goals imposed on the system design have been met. The PMS meets its unavailability allocation, (i.e., the PMS together with the DAS shall contribute less than 3.0 hours per year to the overall plant unavailability). The PMS is designed to contribute less than 2.5 hours per year to the plant unavailability calculations. The primary design features provided by the PMS to meet this requirement include the following:

- the ability to withstand single failures, including loss of power sources
- provision made for the periodic in-situ testing of equipment
- modular design allowing on-line replacement
- extensive diagnostic facilities to identify the location of faulty modules and components
- a V&V program to demonstrate the adequacy of the hardware and software

The above reliability criterion is based on the deterministic criteria of IEEE Std 603-1991 and IEEE Std 7-4.3.2-1993, as discussed under Section 5 of IEEE Std 603-1991.

Based on the discussion above, the staff finds that the AP1000 design meets this requirement in Section 4.9 of IEEE Std 603-1991.

- Section 4.10 of IEEE Std 603-1991 requires identification of the critical points in time or plant conditions for which the protective actions must be initiated. The PMS automatically initiates appropriate protective actions when a condition monitored by the system reaches a preset level. The critical points in time are determined by the PMS response time modeled in the accident analyses. The PMS will be designed and tested to meet the response times assumed in the accident analyses. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of IEEE Std 603-1991.

- Section 4.11 of IEEE Std 603-1991 requires that equipment protective features are designed to place the safety system in a safe state. In the AP1000 design, each protection feature has different characteristics; therefore, different techniques are used to achieve a fail-safe design. The protective features for selected functions include the following:

  - Reactor trip circuits are designed to fail in the tripped state.
  - The actuated components of the engineered safety features are designed to fail into a state that has been demonstrated to be acceptable if conditions such as disconnection, loss of power source, or postulated adverse environments are experienced.

- Sensor circuits are designed so that a loss of power will produce a "safe" signal, or will produce an off-scale value or a signal that can be identified by the protection system as "bad." Digital protective equipment input circuits are designed to recognize off-scale or bad values and take appropriate action (e.g., alarm, actuate, or use substitute value from redundant channel).

- Actuation signals from multiple protection system divisions are provided to improve the reliability of the protection system.

Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.11 of IEEE Std 603-1991.

- Section 4.12 of IEEE Std 603-1991 requires identification of any other special design basis that may be imposed on the system design. The AP1000 has a DAS which is a non-safety system that is diverse and separate from the safety-related PMS. The DAS provides functions necessary to reduce the risk associated with postulated common-mode failures of critical protection systems. Based on the discussion above, the staff finds that the AP1000 design meets this requirement of Section 4.12 of IEEE Std 603-1991.

Section 5 of IEEE Std 603-1991, "Safety System Criteria," requires that the safety systems, with precision and reliability, maintain plant parameters within acceptable limits established for each design-basis event. The power, instrumentation, and control portions of each safety system shall be comprised of more than one safety group, any one of which can accomplish the safety function. The following are the staff's findings with respect to the conformance of the AP1000 design with each of the criteria found in Section 5 of IEEE Std 603-1991:

- Section 5.1 of IEEE Std 603-1991, "Single Failure Criterion," requires the AP1000 safety system to include sufficient redundancy to meet system performance requirements, even if the system is degraded by a single failure. Redundancy begins with the sensors monitoring the variables and continues through the signal processing and actuation electronics. Redundant actuations are also provided. Two or more diverse functions initiate most protective actions. No single failure within the safety system causes a Condition II event to progress to a Condition III event, or a Condition III event to progress to a Condition IV event. To prevent common-mode failures, additional measures, such as functional diversity, physical separation, and testing, as well as administrative control during design, production, installation, and operation, will be employed. Based on the discussion above, the staff finds that the AP1000 design meets this criterion of IEEE Std 603-1991.

- Section 5.2 of IEEE Std 603-1991, "Completion of Protective Action Criterion," requires the AP1000 design to provide features to ensure that system-level actions go to completion. In the AP1000 design, the operator can stop the action of an ESF (on a component-by-component basis) by deliberate intervention. Component-level manual reset controls permit the operator to take this action only after the system-level signal is reset. The provision for component-level manual reset is to stop safeguard functions due to inadvertent actuation. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.3 of IEEE Std 603-1991, "Quality Criterion," applies to the quality assurance provisions for the AP1000 design. The AP1000 quality assurance program conforms to GDC 1. *The design V&V program demonstrates the adequacy of the hardware and* software for the PMS. The software development process is consistent with the following standards:

  - IEEE Std 7-4.3.2-1993, "IEEE Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations"
  - IEEE Std 828-1990, "IEEE Standard for Software Configuration Management Plans"
  - IEEE Std 829-1983, "IEEE Standard for Software Test Documentation"
  - IEEE Std 830-1993, "Recommended Practice for Software Requirements Specifications"
  - IEEE Std 1012-1986, "IEEE Standard for Software Verification and Validation Plans"
  - IEEE Std 1028-1988, "IEEE Standard for Software Review and Audit"
  - IEEE Std 1042-1987, "IEEE Guide to Software Configuration Management"

  WCAP-13383, "AP600 Instrumentation and Control Hardware and Software Design Verification and Validation Process Report," provides a planned design process for Eagle System hardware and software development during the following life cycle stages:

  - design requirement phase
  - system definition phase
  - hardware and software development phase
  - system test phase
  - installation phase

  WCAP-15927 provides a planned design process for Common Qualified Platform system hardware and software development during the following life cycle stages:

  - conceptual phase
  - system definition phase
  - software design phase
  - hardware design phase
  - software implementation phase
  - hardware implementation phase

- system integration phase
- installation phase

Topical Reports WCAP-13383 and CENPD-396-P provide guidance on the design process, the V&V process, and the commercial dedication process.

The applicant states that these processes conform to IEEE Std 7-4.3.2-1982 and other IEEE standards related to software quality and guidance documents. Based on the review of these documents, the staff finds that the processes meet the acceptance criteria, and the PMS design satisfies this criterion of IEEE Std 603-1991.

- Section 5.4 of IEEE Std 603-1991, "Equipment Qualification Criterion," requires that the safety system equipment be qualified by type test, previous operating experience, or analysis, or any combination of these three methods, to substantiate that it will be capable of continually meeting the performance requirements, as specified in the design basis. The staff has reviewed the information in DCD Tier 2, Sections 3.10 and 3.11, and determined that the AP1000 electrical equipment within the safety system is environmentally and seismically qualified to meet the conditions through which it must operate to mitigate the consequences of the accident. Therefore, the staff finds that the PMS design satisfies this criterion of IEEE Std 603-1991.

- Section 5.5 of IEEE Std 603-1991, "System Integrity Criterion," requires that the safety system accomplish its safety functions under the full range of applicable conditions enumerated in the design basis. The AP1000 PMS is designed to maintain its capability to initiate its protective functions during and following natural phenomena that are credible to the plant, such as earthquakes, tornadoes, hurricanes, floods, and winds. Functional capability of the system is also maintained during events such as fires, flooding, explosions, missiles, electrical faults, and pipe whip. The equipment is environmentally and seismically qualified. Therefore, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.6 of IEEE Std 603-1991, "Independence Criterion," requires that redundant portions of a safety system provided for a safety function be independent of and physically separated from each other to the degree necessary to retain the capability to accomplish the safety function during and following any design-basis event requiring that safety function. The AP1000 design maintains physical separation of redundant safety divisions throughout the system, extending from the sensors to the devices actuating the protective function. Separation of wiring is achieved using separate wire ways, cable trays, and containment penetrations for each division. Separate power feeds energize each redundant protection division. Cable separation and conformance to RG 1.75 will be further discussed in Chapter 8 of this report. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.7 of IEEE Std 603-1991, "Capability for Test and Calibration Criterion," requires that safety system equipment be provided with the capability for testing and calibration, while retaining the capability to accomplish their safety functions. The AP1000 design provides that testing from sensor inputs of the PMS to the actuated equipment is accomplished through a series of overlapping sequential tests, the majority of which are capable of being performed with the plant at full power. For those instances in which testing final equipment at power would upset plant operation or damage equipment, provisions are made to test the equipment at reduced power or when the reactor is shutdown. Each division of the PMS includes a test subsystem. The test subsystem does not test the ESF actuators. This portion of the test may be accomplished by using component-level actuation signals. For those final devices that can be operated at power without upsetting the plant or damaging the equipment, the test is performed by actuating the manual actuation control that causes the device to operate. Position switches on the device itself send a signal back to the ESF actuation subsystem, where it is transmitted to the MCR for display. The display verifies that the manual command is successfully completed. When the channel is bypassed for testing, the bypass is manually instated and removed by the test subsystem. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.8 of IEEE Std 603-1991, "Information Display Criterion," requires that the display instrumentation for manual actions necessary to accomplish the safety function be part of the safety system. The display instrumentation shall provide accurate, complete, and timely information. If the protective actions of some part of a safety system have been bypassed for any purpose, continued indication of this fact for each affected safety group shall be provided in the control room. The AP1000 DCD states that no manual controlled actions are assumed in the DCD Tier 2, Chapter 15 analyses; therefore, no Type A variables (a variable that provides information needed by the operator to perform manual actions associated with design-basis accident events) are defined for the postaccident monitoring instrument. The PMS status information available to the operator includes parameter values, logic status, equipment status, and actuation device status. An alarm alerts the operator of deviations from normal operating conditions. The PMS provides the operator (via the data display and processing system) with continuous indication of bypassed status. The majority of the operations employ soft controls, soft control displays, and plant information displays. These displays appear on display devices such as cathode tubes, flat panel screens, or visual display units. The AP1000 human system interface design includes a minimum inventory of dedicated or fixed-position display and controls. The minimum inventory display and controls will perform critical safety functions. Based on the review of information in DCD Tier 2, Chapters 7 and 18, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.9 of IEEE Std 603-1991, "Control of Access Criterion," requires that the design permit the administrative control of access to safety system equipment. These administrative controls shall be supported by provisions within the safety systems, by provisions in the generating station design, or by a combination thereof. The AP1000 design PMS provides for administrative control of access to the means for manually bypassing protection channels and for manually blocking protective functions.

Administrative control of access is provided to setpoint adjustments, channel calibration adjustments, and test points. Cabinet doors are normally locked. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.10 of IEEE Std 603-1991, "Safety System Repair Criterion," requires that the safety systems be designed to facilitate timely recognition, location, replacement, repair, and adjustment of malfunctioning equipment. The AP1000 DCD states that the PMS facilitates the recognition, location, replacement, repair, and adjustment of malfunctioning components or modules. The built-in diagnostics provide a mechanism for periodically verifying the operability of modules in the PMS, and of rapidly locating malfunctioning assemblies. Continuous on-line error checking also detects and locates failures. Channel bypass permits replacement of malfunctioning sensors or channel components (without jeopardizing plant availability), while still meeting the single-failure criterion. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.11 of IEEE Std 603-1991, "Identification Criterion," requires that (1) safety system equipment be distinctly identified in accordance with the requirements of IEEE Std 384-1992, (2) components or modules mounted in equipment or assemblies that are clearly identified as being in a single redundant portion of a safety system do not themselves required identification, (3) identification of safety system equipment be distinguishable from other purposes, (4) identification of safety system equipment not require frequent use of reference material, and (5) the associated documentation be distinctly identified. The AP1000 DCD states that redundant divisions of the safety system have distinctive markings. The color-coded nameplates provide identification of equipment associated with protective functions and their division associations. Noncabinet-mounted protective equipment and components have an identification tag or nameplate. Small electrical components, such as relays, have nameplates on the enclosure that houses them. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.12 of IEEE Std 603-1991, "Auxiliary Features Criterion," states that (1) auxiliary supporting features shall meet all requirements of this standard, and (2) other auxiliary features that perform a function that is not required for the safety systems to accomplish their safety functions, or are part of the safety system by association, shall be designed to meet those criteria necessary to ensure that these components, equipment, and systems do not degrade the safety systems below an acceptable level. The AP1000 DCD states that the AP1000 electrical power system provides reliable power for the safety equipment required for the plant I&C system and other vital functions needed for shutdown of the plant. For the station blackout situation, the dc batteries constitute the source of electrical power for operation of the required dc and alternating current (ac) instrument UPS. When ac power is available, the non-safety-related nuclear island nonradioactive ventilation system (VBS) provides HVAC service to the instrument room and the MCR. If the VBS is not available, the MCR emergency habitablilty system provides emergency passive heat sinks for the instrument room, MCR, and dc equipment room. The heat sink for each room limits the temperature rise inside each room during the 72-hour period. If power is lost for more than 72 hours, the temperature of the instrument room and the MCR will be maintained by operating two ancillary fans to supply outside air to these areas. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.13 of IEEE Std 603-1991, "Multi-Unit Stations Criterion," requires that the sharing of structures, systems, and components (SSCs) between units at multi-unit generating stations is permissible, provided that the ability to simultaneously perform required safety functions in all units is not impaired. The AP1000 DCD states that the AP1000 is a single-unit plant. If more than one unit were built on the same site, the units would not share any of the safety systems. Based on the discussion above, the staff finds that the AP1000 design satisfies this criterion of IEEE Std 603-1991.

- Section 5.14 of IEEE Std 603-1991, "Human Factor Considerations Criterion," states that human factors shall be considered at the initial stages, and throughout the design process, to ensure that the functions allocated in whole or in part to the human operator(s) and maintainer(s) can be successfully accomplished to meet the safety system design goals. The AP1000 human factors engineering design process has been developed to conform to NUREG-0711, "Human Factors Engineering Program Review Model." The 10 elements of the design process provides a structured, top-down system analysis using accepted human factors engineering principles. Chapter 18 of this report further discusses the human factor design process review.

- Section 5.15 of IEEE Std 603-1991, "Reliability Criterion," requires that for those systems for which either quantitative or qualitative reliability goals have been established, appropriate analysis of the design shall be performed in order to confirm that such goals have been achieved. Chapter 26 of the AP1000 PRA report discusses I&C safety systems PRA. Chapter 19 of this report addresses the PRA aspect of the PMS.

Based on its review of the DCD commitments and other docketed references, the staff reached the following conclusions:

- The staff evaluated the PMS design description in the DCD and compared it to the SRP, applicable RGs, and industry codes and standards (including the information required by IEEE Std 603-1991, Sections 4 and 5). Based on its review, the staff concludes that the design meets the appropriate SRP criteria. The staff also concludes that the PMS meets the design-basis requirements of IEEE Std 603-1991.

- The PMS includes systems and components that the applicant has committed to design to survive the effects of earthquakes, other natural phenomena, abnormal environments, and missiles, as discussed in DCD Tier 2, Chapter 3. Therefore, the staff concludes that the applicant's commitments meet the requirements of GDC 2 and 4 for the PMS.

- The staff concludes that the design for the PMS described in DCD Tier 2, Chapters 6, 7, and 15, and DCD Tier 1, Section 2.5.2, provides instrumentation to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences (AOOs), and accident conditions, as appropriate to ensure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant boundary, and the containment and its associated systems. As described above, the staff concludes that appropriate controls are provided to maintain the variables and systems within prescribed ranges. Therefore, the staff finds that the PMS design satisfies the requirements of GDC 13 and 19.

- The staff concludes that the design of the PMS has the capability to (1) initiate automatically the operation of the reactivity control systems to ensure that specified acceptable fuel design limits are not exceeded as a result of AOOs and (2) sense accident conditions and initiate the operation of systems and components important to safety. Therefore, the requirements of GDC 20 are satisfied.

- The staff concludes that periodic testing of the PMS, as described in the DCD, conforms to the criteria of RG 1.22, "Periodic Testing of Protection System Actuation Functions," and RG 1.118. The staff further concludes that the applicant's commitments to IEEE Std 603-1991, with regard to system reliability and testability, are consistent with the requirements of GDC 21 and are, therefore, acceptable.

- The staff concludes that the design of the PMS meets the criteria of RG 1.75 for protection system independence. The design techniques, such as functional diversity and diversity in components, are designed, to the extent practical, to prevent loss of protection function. Therefore, the staff concludes that the PMS meets the requirements of GDC 22.

- Based on the staff's review of the results of the failure modes analysis for the PMS, in conjunction with the results of the studies of the PMS design for defense against common-mode failures as discussed in Section 7.1.6 of this report, the staff concludes that the PMS design meets the requirements of GDC 23.

- The staff finds that the PMS is designed to meet the requirements of IEEE Std 603-1991 regarding protection and control system interaction. Therefore, the staff concludes that the PMS design meets the requirements of GDC 24.

- The staff concludes that the PMS satisfies the protection system requirements for malfunction of the reactivity control system, such as accidental withdrawal of control rods. DCD Tier 2, Chapter 15, addresses the capability of the system to ensure that fuel design limits are not exceeded for such events. Therefore, the staff finds that the PMS satisfies the requirements of GDC 25.

- Based on its review of the PMS design for compliance with all of the above GDC, the staff concludes that the PMS provides protection against AOOs. Therefore, the staff finds that the PMS satisfies the requirements of GDC 29.

- On the basis of the applicant's commitment to meet the requirements of 10 CFR 50.55a(h)(3) with regard to IEEE Std 603-1991, and the staff's conclusions noted above, the staff concludes that the requirements of 10 CFR 50.55a(h) are satisfied.

7.3 Engineered Safety Features Actuation Systems

7.3.1 System Description

This section describes the instrumentation and controls for equipment to initiate various engineered safety features. Because the engineered safety features actuation systems (ESFAS) are part of the PMS, the evaluation of the design and qualification of the PMS, as discussed in Section 7.2 of this report, also applies to the ESFAS.

Four sensors normally monitor each variable used for an ESF actuation. Analog measurements are converted to digital form by analog-to-digital converters within each of the four divisions of the PMS. Following required signal conditioning or processing, the measurements are compared against the setpoints for the ESF to be activated. When the measurement exceeds the setpoint, the output of the comparison results in a channel partial trip condition. The partial trip information is transmitted to the ESF coincidence logic to form the signals that result in an ESF actuation. The voting logic is performed twice within each division. Each voting logic element generates an actuation signal, if the required coincidence of partial trips exists at its inputs. The signals are combined within each division of ESFAS coincidence logic to generate a system-level signal.

The system-level signals are then broken down to the individual signals to actuate each component associated with a system-level ESF. The interposing logic accomplishes this function and also performs necessary interlocking so that components are properly aligned for safety. Component-level manual actions are also processed by this interposing logic. The power interface transforms the low-level signals to voltages and current commensurate with the actuation devices it operates. The actuation devices, in turn, control motive power to the final ESF component.

The safeguard actuation function is necessary to mitigate the effects of high-energy line breaks, both inside and outside of containment. A safeguards actuation (S) signal actuates the alignment of the valves of the core makeup tank (CMT) for passive injection to the RCS. The S signal provides two primary functions:

(1) primary side water addition to ensure maintenance or recovery of reactor vessel (RV) water level

(2) boration to ensure recovery and maintenance of shutdown margin (k_{eff} less than 1.0)

The S signal also initiates the reactor trip, turbine trip, reactor coolant pump trip, containment isolation, main feedwater control valves closure, main feedwater pump trip, and closure of isolation and crossover valves.

The S signal is generated by any of the following initiating conditions:

- low pressurizer pressure
- low lead-lag compensated steamline pressure
- low reactor coolant inlet temperature
- high-2 containment pressure
- manual initiation

The following subsections describe the signals and initiation logic for each ESF.

7.3.1.1 Containment Isolation

Containment isolation provides isolation of the containment atmosphere and selected process systems which penetrate containment from the environment. This function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large-break, loss-of-coolant accident (LOCA).

A signal to actuate containment isolation is generated by any of the following conditions:

- automatic or manual safeguards actuation signal
- manual initiation
- manual actuation of passive containment cooling

Manual reset is provided to block the automatic actuation signal for containment isolation. Separate momentary controls are provided for resetting each division. No other interlocks or permissive signals apply directly to the containment isolation function.

7.3.1.2 In-Containment Refueling Water Storage Tank Injection

The passive core cooling system (PXS) provides core cooling by gravity injection and recirculation for decay heat removal following an accident. The in-containment refueling water storage tank (IRWST) has two injection flow paths. Each injection path includes a motor-operated isolation valve, which is normally open, and two parallel lines, each isolated by one check valve and one squib valve in series.

The IRWST injection upon a low-2 hot-leg level is automatically blocked when the pressurizer water is above the P-12 setpoint. This reduces the probability of a spurious injection. This block is removed when the CMT actuation on low pressurizer level function is manually blocked to allow mid-loop operation.

The following conditions will generate signals to align the IRWST for injection:

- actuation of the fourth stage of the automatic depressurization system
- coincidence loops 1 and 2 hot-leg levels below the low-2 setpoint for a duration exceeding an adjustable time delay
- manual initiation

7.3.1.3 Core Makeup Tank Injection

The CMT injection provides for the passive injection of borated water into the RCS. Injection provides RCS makeup water and boration during transients or accidents when the normal makeup supply from the chemical and volume control system (CVS) is lost or insufficient. Two tanks are provided. CMT injection mitigates the effects of high-energy line breaks by adding primary side water to ensure maintenance or recovery of the RV water level following a LOCA, and by borating to ensure recovery or maintenance of shutdown margin following a steamline break.

The following conditions will generate signals to align the CMTs for injection:

- automatic or manual safeguards actuation
- automatic or manual actuation of the first stage of the automatic depressurization system
- low-2 pressurizer level
- low wide-range steam generator level coincident with high hot-leg temperature
- manual initiation
- pressurizer water level increasing above the P-12 interlock

7.3.1.4 Automatic Depressurization System Actuation

The automatic depressurization system (ADS) provides a sequenced depressurization of the RCS to allow passive injection from the accumulators, and the IRWST to mitigate the effects of a LOCA. The depressurization is accomplished in four stages, with the first three stages discharging into the IRWST and the last stage discharging into containment. Each of the first three stages consists of two parallel paths, with each path containing an isolation valve and a depressurization valve.

Any of the following conditions will generate a signal to actuate the first stage of the ADS:

- core makeup tank injection alignment signal coincident with a core makeup tank level less than the low-1 setpoint in two of the four divisions of either of the two core makeup tanks
- extended loss of ac power sources
- manual initiation

The first stage depressurization valves are opened following a preset time delay after the actuation of the isolation valves. The second stage isolation valves are opened following a preset time delay after first stage depressurization valves open. The second stage depressurization valves are opened following a preset time delay after the second stage isolation valves are actuated, similar to stage one. The third stage isolation valves are opened following a preset time delay after the opening of the second stage depressurization valves. The third stage depressurization valves are opened following a preset time delay after the third stage isolation valves are actuated.

The fourth stage of the ADS consists of four parallel paths. Each of these paths consists of an isolation valve which is normally open and a depressurization valve. The four paths are divided into two groups with two paths in each group. The fourth stage valves can be opened under three conditions:

- manual initiation coincident with low wide-range pressure of the reactor coolant system or actuation of the automatic depressurization system stages 1, 2, and 3
- a low-2 core makeup tank level coincident with a low wide-range pressure of the reactor coolant system and ADS stage 1, 2, and 3 actuation
- coincident of RCS loops 1 and 2 low-2 hot-leg levels

7.3.1.5 <u>Reactor Coolant Pump Trip</u>

The RCP trip allows the passive injection of borated water into the RCS. Injection provides RCS makeup water and boration during transients or accidents when the normal makeup supply from the CVS is lost or insufficient. When the RCP pumps are tripped, two tanks provide passive injection of borated water by gravity. The CMT injection mitigates the effects of high-energy line breaks by adding primary-side water to ensure maintenance or recovery of the water level in the RV following a LOCA, and by borating to ensure recovery or maintenance of shutdown margin following a steamline break. The RCP trip upon high bearing water temperature protects the RCS coastdown.

Any one of the following conditions will generate a signal to trip the reactor coolant pumps:

- automatic or manual safeguards actuation signal

- automatic or manual actuation of the first stage of the automatic depressurization system

- low-2 pressurizer level

- low wide-range steam generator level coincident with high hot-leg temperature

- manual initiation of core makeup tank injection

- high reactor coolant pump bearing water temperature

7.3.1.6 <u>Main Feedwater Isolation</u>

The primary functions of the main feedwater isolation are to (1) prevent damage to the turbine due to water in the steamlines and (2) stop excessive flow of feedwater into the SGs.

Any of the following conditions will generate signals to isolate the main feedwater supply to the SGs:

- automatic or manual safeguards actuation
- manual initiation
- high-2 steam generator narrow-range water level
- low-1 reactor coolant system average temperature coincident with P-4 permissive logic
- low-2 reactor coolant system average temperature coincident with P-4 permissive logic

7.3.1.7 <u>Passive Residual Heat Removal Heat Exchanger Alignment</u>

The heat exchanger in the passive residual heat removal (PRHR) system provides emergency core decay heat removal when the startup feedwater system is not available to provide a heat sink.

Any of the following conditions will generate a signal to align the PRHR heat exchanger to passively remove core heat:

- core makeup tank injection alignment signal
- first stage automatic depressurization system actuation
- low wide-range steam generator level
- low narrow-range steam generator level coincident with low startup feedwater flow
- high-3 pressurizer water level
- manual initiation

7.3.1.8 <u>Turbine Trip</u>

The primary function of the turbine trip is to prevent damage to the turbine due to water in the steamlines. This function is necessary in MODES 1 and 2, and in MODE 3 above P-11 to mitigate the effects of a large steamline break (SLB) or a large feedline break. Failure to trip the turbine following an SLB or a large feedline break can lead to the delivery of additional mass and energy to the SGs, resulting in excessive cooldown and an additional mass and energy release in containment.

Any of the following conditions will generate a signal to initiate turbine trip:

- reactor trip
- high-2 steam generator narrow-range water level
- manual feedwater isolation

7.3.1.9 In-Containment Refueling Water Storage Tank Containment Recirculation

The PXS provides core cooling by gravity injection and recirculation for decay heat removal following an accident. The PXS has two containment recirculation flow paths. Each path contains two parallel flow paths; one path is isolated by a motor-operated valve in series with a squib valve, and the other path is isolated by a check valve in series with a squib valve.

The following conditions will generate signals to align the IRWST:

- low-3 IRWST water level coincident with fourth stage automatic depressurization system actuation

- manual initiation

- extended loss of ac power sources

7.3.1.10 Steamline Isolation

Isolation of the main steamlines provides protection in the event of an SLB inside or outside containment. For an SLB upstream of the isolation valves, closure of these valves limits the accident to the blowdown from only the affected SG. For an SLB downstream of the isolation valves, closure of the valves terminates the accident as soon as the steamline depressurizes.

Any of the following conditions will generate a signal to isolate the steamline:

- manual initiation
- high-2 containment pressure
- low lead-lag compensated steamline pressure
- high steamline pressure negative rate
- low reactor coolant inlet temperature

7.3.1.11 Steam Generator Blowdown System Isolation

Steam generator blowdown isolation is provided to preserve the SG water inventory in anticipation of the use of the PRHR system. One of the following signals will initiate SG blowdown isolation:

- passive residual heat removal heat exchanger alignment signal
- low narrow-range steam generator level

7.3.1.12 Passive Containment Cooling Actuation

The passive containment cooling system has no containment heat removal function during normal plant operations. It is continuously maintained for readiness to respond in an emergency. The passive containment cooling system is actuated by:

- manual initiation
- high-2 containment pressure

The actuation signal opens the passive containment cooling system valves to allow gravity flow from the passive containment cooling water storage tank to the top of the containment shell. The evaporation of the water on the containment shell provides the passive cooling.

7.3.1.13 Startup Feedwater Isolation

Isolation of the startup feedwater system is provided to prevent reactor overcooling effects or SG overfill that may damage the main turbine. One of the following three signals will initiate the startup feedwater system isolation:

- low reactor coolant inlet temperature
- high-2 steam generator narrow-range water level
- manual actuation of main feedwater isolation

The low reactor coolant inlet temperature signal is interlocked with the P-11 permissive logic. The isolation signal closes the startup feedwater control and isolation valves and trips the startup feedwater pump.

7.3.1.14 Signal to Block Boron Dilution

This function is provided to protect against malfunctions of the CVS leading to unacceptable boron dilution during shutdown. On a coincidence of two of the four divisions, boron dilution is blocked. The flux doubling signal may be blocked manually above the P-6 power level and is automatically reinstated below the P-6 permissive logic.

Any of the following conditions will generate signals to block boron dilution:

- excessive increasing rate of source range nuclear power
- loss of ac power sources
- reactor trip

7.3.1.15 Chemical and Volume Control System Isolation

The safety functions provided by the CVS are limited to (1) containment isolation of the CVS lines penetrating containment, (2) termination of inadvertent RCS boron dilution, (3) isolation of makeup on an SG or pressurizer high level signal, and (4) preservation of the RCS pressure boundary, including isolation of normal CVS letdown from the RCS.

The following conditions will generate the signal to actuate the isolation of the CVS:

- high-2 pressurizer level
- high-2 steam generator narrow-range water level
- automatic or manual safeguards actuation signal coincident with high-1 pressurizer level
- high-2 containment radioactivity
- manual initiation

7.3.1.16 Signal to Block Steam Dump

Either of the following conditions will generate signals to block the steam dump (turbine bypass):

- low-2 reactor coolant system average temperature coincident with P-4 permissive logic
- manual initiation

7.3.1.17 Control Room Isolation and Air Supply Initiation

Isolation of the MCR and initiation of the air supply provides a protected environment from which operators can control the plant following an uncontrolled release of radioactivity. One of the following conditions will generate signals to initiate isolation of the MCR, initiate the air supply, and open the control room pressure relief isolation valves:

- high-2 control room air supply radioactivity level
- loss of ac power sources
- manual initiation

7.3.1.18 Auxiliary Spray and Letdown Purification Line Isolation

The CVS maintains the RCS fluid purity and activity level within acceptable limits. The CVS purification line receives flow from the discharge of the RCPs. The CVS also provides auxiliary spray to the pressurizer. To preserve the reactor coolant pressure in the event of a break in the CVS loop piping, the purification line and the auxiliary spray line are isolated on a pressurizer water level low-1 setpoint in any two of the four divisions. This helps maintain reactor coolant system inventory.

7.3.1.19 Containment Air Filtration System Isolation

Some design-basis accidents, such as a LOCA, may release radioactivity into the containment where the potential would exist for the radioactivity to be released to the atmosphere and exceed the acceptable site dose limit. Isolation of the containment air filtration system provides protection to prevent radioactivity inside the containment from being released to the atmosphere.

Any of the following conditions will generate a signal to isolate the containment air filtration system:

- automatic or manual safeguards actuation signal
- manual actuation of containment isolation
- manual actuation of passive containment cooling
- high-1 containment radioactivity

7.3.1.20 Normal Residual Heat Removal System Isolation

The suction line of the normal residual heat removal system (RNS) is isolated by closing the containment isolation valves upon high-2 containment radioactivity. This will provide containment isolation following an accident. This line is isolated on a safeguards actuation signal. However, the valves may be reset to permit the RNS pumps to perform their defense-in-depth functions following an accident. Should a high containment radiation signal (above high-2 setpoint) develop following the containment isolation signal, the RNS valves would reclose.

Any one of the following conditions will generate signals for isolating the RNS lines:

- automatic or manual safeguards actuation signal
- high-2 containment radioactivity
- manual initiation

7.3.1.21 Refueling Cavity Isolation

The containment isolation valves in the lines between the refueling cavity and the spent fuel pool cooling system are isolated when a low spent fuel pool level occurs in two out of three divisions. This helps to maintain the water inventory in the refueling cavity due to line leakage.

7.3.1.22 Chemical and Volume Control System Letdown Isolation

The occurrence of a low-1 hot-leg level in either of the two hot-leg loops will generate a signal to isolate the letdown valves of the CVS. This helps to maintain reactor system inventory. These letdown valves are also closed by the containment isolation function.

7.3.1.23 Pressurizer Heater Block

Pressurizer heaters are automatically tripped upon receipt of a CMT operation signal or a high-3 pressurizer water level signal. This pressurizer heater trip reduces the potential for SG overfill and automatic ADS Stages 1, 2, and 3 actuation for an SG tube rupture event. Automatically tripping the pressurizer heaters reduces the pressurizer level swell for certain non-LOCA events (such as loss of normal feedwater, inadvertent CMT operation, and CVS malfunction resulting in an increase in RCS inventory). For small-break LOCA analysis, tripping the pressurizer heaters supports depressurization of the RCS following actuation of the CMTs.

Either one of the following conditions will generate signals to block the operation of the pressurizer heaters:

- core makeup tank injection alignment signal
- high-3 pressurizer water level

7.3.1.24 Steam Generator Relief Isolation

The function of the SG power-operated relief valve (PORV) and block valve isolation is to ensure that the SG PORV flow paths can be isolated during a steam generator tube rupture (SGTR) event. The PORV flow paths must be isolated following an SGTR to minimize radiological release from the ruptured SG into the atmosphere. During the SGTR, the PORV flow path is assumed to open due to high secondary-side pressure. Dose analyses take credit for subsequent isolation of the PORV flow path by the PORV and/or the block valve which receive a close signal upon low steamline pressure.

Either of the following conditions will generate a signal to close the SG PORVs and their block valves:

- manual initiation
- low lead-lag compensated steamline pressure

7.3.2 Blocks, Permissives, and Interlocks for Engineered Safety Features Actuation

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock functions back up manual actions to ensure plant operation under the conditions assumed in the safety analyses. The interlocks for ESFAS are as follows:

- The P-4 interlock (reactor trip) is enabled when the reactor trip breakers in two out of the four divisions are open. It is also enabled by all automatic reactor trip actuations. The P-4 interlock may—
  - trip the main turbine
  - permit the block of automatic safeguards actuation after time delay

- block boron dilution
- isolate main feedwater coincident with low reactor coolant temperature

- The P-6 interlock intermediate range neutron flux is actuated when the intermediate range channel of the respective nuclear instrumentation system goes approximately one decade above the minimum channel reading. Above the setpoint, the P-6 interlock allows a manual block of the flux doubling actuation, thereby blocking boron dilution.

- The P-11 interlock (pressurizer pressure) permits a normal unit cooldown and depressurization without safeguards actuation or main steamline and feedwater isolation. With pressurizer pressure channels less than the P-11 setpoint, the interlock may—

  - permit manual block of safeguards actuation upon low pressurizer pressure, low compensated steamline pressure, or low reactor coolant inlet temperature

  - permit manual block of steamline isolation upon low reactor coolant inlet temperature

  - permit manual block of steamline isolation and SG PORV block valve closure upon low compensated steamline pressure

  - automatically unblock steamline isolation upon high negative steamline pressure rate, coincident with manual actions of items 2 and 3 above

  - permit manual block of main feedwater isolation upon low reactor coolant temperature

  - permit manual block of startup feedwater isolation upon low reactor coolant inlet temperature

  - permit manual block of steam dump block upon low reactor coolant temperature

  - permit manual block upon normal RNS isolation triggered by high containment radioactivity

- The P-12 interlock (pressurizer level) is provided to permit mid-loop operation without CMT actuation, IRWST actuation, reactor coolant pump trip, or purification line isolation. With pressurizer level channels less than the P-12 setpoint, the interlock may—

  - permit manual block of CMT actuation upon low pressurizer level to allow mid-loop operation

  - permit manual block of RCP trip upon low pressurizer level to allow mid-loop operation

- permit manual block of auxiliary spray and purification line isolation upon low pressurizer level to allow mid-loop operation

- automatically unblock IRWST injection and fourth stage ADS initiation upon low hot-leg level to provide protection during mid-loop operation, coincident with manual action of (A)

• The P-19 interlock (RCS pressure) is provided to permit water solid conditions in lower modes without automatic isolation of the CVS makeup pumps. With RCS pressure below the P-19 setpoint, the interlock may—

  - permit manual block of CVS isolation upon high pressurizer water level

  - permit manual block of PRHR heat exchanger alignment upon high pressurizer water level

7.3.3 Essential Auxiliary Supporting Systems

In the AP1000 design, many essential auxiliary supporting systems traditionally classified as safety-related are classified as non-safety-related, defense-in-depth systems that are important to safety. Their implementation requires regulatory oversight in accordance with SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," which identifies the staff's position on technical and policy issues pertaining to the regulatory treatment of non-safety systems (RTNSS) for passive ALWRs. The applicant uses PRA insights to identify SSCs that are important in protecting the utility's investment and in preventing and mitigating severe accidents.

To provide reasonable assurance that these SSCs are operable during anticipated events, short-term availability controls are provided. These short-term availability controls define—

• which equipment should be operable
• operational modes when the equipment should be operable
• testing and inspections that should be used to demonstrate the equipment's operability
• operational modes that should be used for planned maintenance operations
• remedial actions that should be taken if the equipment is not operable

These systems are included in the reliability assurance program and the operational reliability assurance process.

The following systems are included in the short-term availability control program:

• instrumentation systems

  - DAS ATWS mitigation
  - DAS engineered safety features actuation

- plant systems
  - normal residual heat removal system
  - normal residual heat removal system—RCS open (need two trains at MODES 5 and 6)
  - component cooling water system—RCS open (need two trains at MODES 5 and 6)
  - service water system—RCS open (need two trains at MODES 5 and 6)
  - passive containment cooling system water makeup—long-term shutdown
  - main control room cooling—long-term shutdown
  - I&C room cooling—long-term shutdown
  - hydrogen ignitors
- electrical power systems
  - ac power supplies
  - ac power supplies—RCS open (need two trains at MODES 5 and 6)
  - ac power supplies—long-term shutdown
  - non-Class 1E dc and UPS system

Chapter 22 of this report addresses the AP1000 RTNSS evaluation.

7.3.4 ESFAS Evaluation Findings and Conclusions

The staff evaluated the ESFAS design description in the DCD for conformance with the criteria of the SRP, applicable RGs, and industry codes and standards (including the requirements of Sections 4 and 5 of IEEE Std 603-1991 which are codified in 10 CFR 50.55a(h)). The ESFAS detects a plant condition requiring the operation of ESF systems and initiates operation of those systems. Because the ESFAS is part of the PMS, the evaluation of the design and qualification of the PMS, as discussed in Section 7.2 of this report, also applies to the ESFAS.

The staff's review of the ESFAS design focused on the trip parameter sensors, PMS, and protection actuation circuits. On the basis of the staff's review of the information provided in DCD Tier 2, Chapters 6, 7, 8, and 9, and the commitments made in the DCD Tier 1, Table 2.5.2-8, "Inspections, Tests, Analyses, and Acceptance Criteria," the staff concludes that the DCD provides an acceptable design description and commitments to meet the appropriate SRP criteria. In addition, the applicant's commitment to implement the design using the ITAAC process ensures that the ESFAS will perform as designed.

As discussed in Section 7.3.1 of this report, the evaluation of the PMS (as discussed in Section 7.2) applies to the ESFAS. Therefore, the staff concludes that the design of the AP1000 ESFAS meets the relevant requirements of GDC 1, 2, 4, 13, 19–24, 29, 34, 35, and 41; 10 CFR 50.55a(a)(1); and 10 CFR 50.55a(h); therefore, it is acceptable.

7.4 <u>Systems Required for Safe Shutdown</u>

7.4.1 System Description

The I&C necessary to establish and maintain safe-shutdown conditions following an accident are designed to achieve two basic functions:

(1) maintain the core in a subcritical condition
(2) maintain adequate core cooling by removing residual heat

The required functions to accomplish a safe shutdown are reactor trip, coolant circulation, residual heat removal, and depressurization. The ESF systems are designed to establish and maintain postaccident safe-shutdown conditions for the plant.

There are two different safe-shutdown conditions that are expected following a transient or accident condition—short-term safe shutdown and long-term safe shutdown. Short-term safe shutdown refers to plant conditions from the start of an event until about 36 hours later. Long-term safe shutdown refers to the plant conditions after this 36-hour period. The short-term safe-shutdown conditions include maintaining (1) the reactor subcritical; (2) the reactor coolant average temperature less than or equal to no-load temperature, and (3) adequate coolant inventory and core cooling. These shutdown conditions shall be achieved following any of the design-basis events using safety-related equipment. The long-term safe-shutdown conditions are the same as the short-term conditions except that the coolant temperature shall be less than 215.6 °C (420 °F). GDC 34 requires that a plant design include a system to remove residual heat for long-term cooling. This long-term cooling must be achieved within 36 hours and maintained indefinitely using safety-related equipment.

The non-safety-related systems are not required for safe shutdown of the plant. When the plant safe shutdown does not include accident response or mitigation, the non-safety-related systems normally used to support plant shutdown operations are expected to be available to support safe shutdown operations.

The following ESF systems automatically function to place the plant in a safe-shutdown condition without operator action:

- protection and safety monitoring system, including the PRHR heat exchanger, condenser makeup tank, accumulator, IRWST, and automatic depressurization valves of the passive core cooling system

- passive containment cooling system

- Class 1E dc and uninterruptible power supply system
- containment isolation valves
- reactor system
- control rods

For establishing safe-shutdown conditions, control is possible from either the MCR or the remote shutdown workstation. The monitoring instrumentation available in the MCR for safe shutdown is safety-related and is part of the qualified display processing system.

7.4.2 Safe Shutdown from Outside the Main Control Room

If evacuation of the MCR is required because of some abnormal MCR condition, the operator can establish and maintain safe-shutdown conditions at the remote shutdown workstation. The design basis for safe shutdown at the remote shutdown workstation is an event that requires evacuation of the MCR, coincident with the loss of offsite power and a single active failure without a concurrent design-basis accident.

One remote shutdown workstation is provided for the plant, which is similar to the operator workstations in the MCR and is designed to the same standards. The remote shutdown workstation contains controls for the safety-related equipment required to establish and maintain safe shutdown. Additionally, control of non-safety-related components is available, allowing operation and control when ac power is available.

The remote shutdown workstation is provided for use following an evacuation of the MCR only. No actions are anticipated from the remote shutdown workstation during normal, emergency, routine shutdown, refueling, or maintenance operations. Operator control capability at the remote shutdown workstation is normally disabled. Operator control capability can be transferred from the MCR workstations to the remote shutdown workstation if the control room requires evacuation. Procedures will instruct the operator to trip the reactor prior to evacuating the control room and transferring control to the remote shutdown workstation. This operator control transfer capability cannot be disabled by any single active failure coincident with the loss of offsite power.

The control transfer function is implemented by multiple transfer switches. Each individual transfer switch is associated with only one safety-related or one non-safety-related group. These switches are located behind an unlocked access panel. Entry into this panel will result in alarms at the MCR and the remote shutdown workstation. The access panel is located within a fire zone which is separate from the MCR. The manual reactor trip switches located in the MCR are not affected by this control transfer function.

In addition to the controls and indications provided at the remote shutdown workstation, the following controls are provided outside the MCR:

- reactor trip capability at the reactor trip switchgear

- turbine trip capability at the turbine

- start/stop controls for the diesel generators located at each diesel generator local control panel

- local control at motor control centers and electrical switchgear

DCD Tier 2, Section 7.4.3.1.1 states that—

> the operator displays located in the main control room and on the remote shutdown workstation are also not affected by this control transfer function. The displays on the remote shutdown workstation are operational during normal operation (from the main control room) so that they can be utilized with no delay if transfer to the remote shutdown workstation is required.

This is acceptable to the staff because it maintains continuity of operation between the MCR and the remote shutdown workstation, and operators at both locations have indication of the status of the parameters required for safe shutdown before, during, and following transfer between the control room and the remote shutdown workstation.

7.4.3 Evaluation Findings and Conclusions

In DCD Tier 2, Section 7.4, the applicant states that, in the event of a turbine or reactor trip, non-safety-related plant systems automatically function to place the plant in hot standby (i.e., a safe-shutdown condition). Additional non-safety-related systems are available to permit the operator to manually perform normal routine plant depressurization and cooldown. The DCD also states that the ESF systems are designed to establish and maintain safe-shutdown conditions for the plant following an accident. Non-safety-related systems are not required for postaccident safe shutdown of the plant. When available, the operator will rely on the non-safety-related shutdown systems before actuating ESF systems for safe shutdown.

The staff conducted a review of these systems to evaluate their conformance to the guidelines in the RGs and industry standards applicable to these systems. The staff concludes that the DCD has adequately described the guidelines applicable to these systems. Based on the review of the system design for conformance to the guidelines, the staff finds that there is reasonable assurance that the systems fully conform to the guidelines applicable to these systems. Therefore, the staff finds that the requirements of GDC 1 and 10 CFR 50.55a(a)(1) have been met.

The staff's review included the identification of those systems and components in the safe-shutdown systems that are designed to survive the effects of earthquakes, other natural phenomena, abnormal environments, and missiles. Based on the review of DCD Tier 2, Sections 3.10 and 3.11, which address the qualification programs to demonstrate the capability of those systems and components to survive such events, the staff concludes that the AP1000 design has identified such systems and components. Furthermore, the systems and components identified will be qualified consistent with the design bases. This satisfies the requirements of GDC 2 and 4.

Based on its review, the staff concludes that instrumentation and controls have been provided to maintain variables and systems which can affect the fission process, as well as the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems, within prescribed operating ranges during plant shutdown. Therefore, the staff finds that the systems required for safe shutdown satisfy the requirements of GDC 13.

Instrumentation and controls have been provided within the control room to allow actions to be taken to maintain the plant in a safe condition during shutdown, including a shutdown following an accident. Equipment outside the control room has been provided for prompt shutdown of the reactor and to maintain the unit in a safe condition during shutdown. The staff finds that the AP1000 design satisfies the applicable requirements of GDC 19.

The review of the I&C systems required for safe shutdown includes conformance to the requirements for testability, operability with onsite and offsite electrical power, and single-failure criterion. The staff finds that the AP1000 design satisfies the requirements of GDC 34, 35, and 38.

The staff concludes that the design of the safe-shutdown systems is acceptable and meets the relevant requirements of GDC 1, 2, 4, 13, 19, 34, 35, and 38, and 10 CFR 50.55a(a)(1).

7.5 Safety-Related Display Information

7.5.1 System Description

This section describes the instrumentation used by the operator to monitor and maintain safe operation of the AP1000 plant through AOOs and postaccident conditions. The applicant classified the variables for this instrumentation in accordance with the guidance of RG 1.97, except for the addition of the Type F classification, which is unique to the AP1000 design. The six types of variables that provide information to the control room operator are as follows:

(1) Type A variables are needed to diagnose the plant status in accordance with emergency operating instructions. These variables also provide information to assist the operator in taking specified, preplanned, manually controlled actions when automatic actions are not provided to recover from design-basis accidents and achieve a safe-shutdown condition.

There are no specific preplanned, manually-controlled actions for postaccident safe shutdown in the AP1000 design. Therefore, the DCD did not identify a Type A variable.

(2) Type B variables are needed to assess the process of accomplishing or maintaining reactivity control, reactor coolant system integrity, reactor coolant system inventory control, reactor core cooling, heat sink maintenance, and containment integrity.

(3) Type C variables monitor the potential for a gross breach of a fission product barrier, including the in-core fuel cladding, the RCPB, or the primary reactor containment.

(4) Type D variables monitor the performance of plant safety-related systems used to attain a safe-shutdown condition (by mitigating the consequences of an accident) and subsequent plant recovery.

(5) Type E variables monitor the habitability of the main control room. These variables are also used in determining the magnitude of radioactivity releases, assessing releases of radioactive materials, and monitoring radiation levels and radioactivity in the environment surrounding the plant.

(6) Type F variables provide information that allows the control room operators to take specified, preplanned, manually controlled actions using non-safety-related systems to prevent the unnecessary actuation of safety-related systems. These variables are also used by the control room operators to monitor non-safety-related systems used to mitigate the consequences of an accident and subsequent plant recovery, to operate non-safety-related systems used for plant cooldown, and to maintain plant shutdown conditions.

The design and qualification requirements of the instrumentation for the different variable types are divided into the following three categories:

(1) Category 1 instrumentation requires seismic and environmental qualification, application of the single-failure criterion, use of emergency power, and an immediately accessible display.

(2) Category 2 instrumentation requires environmental and seismic qualification commensurate with the required function. It may require emergency power, but not the application of the single-failure criterion or an immediately accessible display. It requires a rigorous performance verification for a single instrument channel.

(3) Category 3 instrumentation does not require qualification, application of the single-failure criterion, use of emergency power, or an immediately accessible display. It meets high-quality, commercial-grade qualification.

The applicant identified all postaccident monitoring variables in DCD Tier 2, Table 7.5-1. DCD Tier 2, Table 7.5-1, also provides information associated with each variable, including instrument ranges, type and category, qualification status, number of instruments required, power supply classification, and whether or not information is available as part of a qualified postaccident indication on the qualified data processing system (QDPS). Based on the review of the information provided in the DCD, the staff concludes that the safety-related display information system for the AP1000 plant is designed in accordance with the guidelines of RG 1.97.

7.5.2 Processing and Display Equipment

The AP1000 processing and display function is performed by equipment which is part of the PMS, PLS, and DDS. The PMS provides signal conditioning, communications, and display functions for Category 1 variables and for Category 2 variables that are energized from the Class 1E dc UPS system. The PLS and the DDS provide signal conditioning, communications, and display functions for Category 3 variables and for Category 2 variables that are energized from the non-Class 1E dc UPS system. The DDS also provides an alternate display of the variables which are displayed by the PMS. Electrical separation of the DDS and PMS is maintained through the use of isolation devices.

The Class 1E position indication signal for each valve and electrical breaker is powered by an electrical division with 24-hour battery capacity. The power associated with the actuation signal for each of these valves or electrical breakers is provided by an electrical division with 24-hour battery capacity; therefore, no need exists to provide position indication beyond this period. The operator will verify that the valves or electrical breakers have achieved the proper position for long-term, stable plant operation before position indication is lost. Electrically operated valves, which have the electrical power removed to meet the single-failure criterion, are provided with redundant valve position sensors. Each of the two position sensors is powered by a different non-Class 1E power source.

7.5.3 Network Gateway (Real-Time to PMS)

DCD Tier 2, Figures 7.1-1 and 7.1-2, depict the network Gateway. In the AP1000 design, the Gateway will provide interfacing between the non-safety real-time data network and the safety-related PMS network. The Gateway is a standard, commercially available device used in communication interfacing. It connects two different network systems, and it will allow communication protocol translation between the networks mentioned above. The Gateway has two subsystems. One subsystem is safety-related and will communicate with systems within each channel of the PMS. The other subsystem will communicate with the real-time data network. Safety channel independence is maintained. The two subsystems are connected via a fiber optic link. The design of the Gateway, as presented in the DCD, is limited in detail because the communication technology available at the time of plant construction may change. Therefore, only the Gateway functional requirements, and their conformance with the applicable GDC and safety-related I&C standards, will be considered at this time.

DCD Tier 2, Section 7.1.2.8 states that there is "no potential signal from the non-safety system that will prevent the PMS from performing its safety function." Furthermore, the Gateway will provide electrical and communication isolation features. This is consistent with GDC 24, which states, in part, that "interconnection of the protection and control systems shall be limited so as to ensure that safety is not significantly impaired." It is also consistent with IEEE Std 7-4.3.2-1993, Section 5.6, which states, in part, that "data communication...shall not inhibit the performance of the safety function." It is important to recognize that the Gateway is a communication interface whose existence is to facilitate data transfer, while not adversely impacting the safety function. Other components within the safety system, discussed elsewhere in this chapter, provide electrical isolation. Furthermore, other components of the safety system will ensure that non-safety control signals do not inhibit safety-related automatic or manual controls. This issue is discussed in DCD Tier 2, Section 7.1.2.8, in terms of the use of application software to ensure that safety functions have priority over non-safety controls.

Even though limited detail is provided in the DCD for the communication architecture, the staff finds the use of the Gateway shown in block diagrams found in DCD Tier 2, Figures 7.1-1 and 7.1-2, to be acceptable. The staff's review of this system included postulating a malicious cyberattack on the safety system from the real-time data network. DCD Tier 2, Section 7.1.2.8 addresses this concern. The staff concludes that any real-time network activity should not prevent the PMS from performing its safety-related function, if the ITAAC design commitment is appropriately implemented.

7.5.4 Operation and Control Centers System

The OCS includes the MCR, technical support center, remote shutdown workstation, emergency operation facility, local control station, and associated workstations for each of these centers. The human system interface design includes the design of the OCS and each of the human system interface resources. The AP1000 human system interface resources include the following:

- wall panel information system
- alarm system
- plant information system
- computerized procedure system
- soft control/dedicated controls
- qualified data processing system

The wall panel information system presents information about the plant for use by the operators. No control capabilities are included. The wall panel information system provides dynamic display of plant parameters and alarm information so that a high level of current plant status can be understood. It provides information important to maintaining the situation awareness of the crew and supporting crew coordination. It also serves as the alarm system overview panel display. The display of plant disturbances (alarms) and plant process data is integrated on this wall panel information system display. The wall panel information system is a non-safety-related system. It is designed to have a high level of reliability.

The AP1000 alarm system provides the operating staff of the operation and control centers with the means for acquiring and understanding the plant's behavior. The alarm system supports the control room crew members by the following steps:

- the "alert" activity, which alerts the operator to off-normal conditions

- the "observe what is abnormal" activity, which aids the user in focusing on the important issues
- the process "state identification" activity, which aids the user in understanding the abnormal conditions, provides corrective action guidance, and guides the operators into the information display system

The plant information system provides dynamic indications of plant parameters and visual alerts. The plant information system uses color graphic video display units located on the workstations in the operation and control centers to display plant process data. These displays provide information important to monitoring, planning, and controlling the operation of plant systems and obtaining feedback on control actions. The displays provided by the plant information system are non-safety-related, but provide information about both safety-related and non-safety-related systems.

The computerized procedure system assists plant operators in monitoring and controlling the execution of plant procedures. The computerized procedure system is accessible from the operator workstations in the MCR. The design of a backup to the computerized procedure system is developed as part of the human system interface design process. Design options to handle the loss of the computerized procedure system include the use of backup procedures written on paper.

The MCR provides a limited set of dedicated control switches and soft controls. The dedicated control switches are used to perform a dedicated single function, with each switch having a single action. The soft control units are used to provide a compact alternative to the traditional control board switches by substituting virtual switches for discrete switches.

The QDPS provides a Class 1E system designed to present the plant parameters which demonstrate the safety of the plant to the MCR operators. The QDPS presents these variables through safety-related displays. The information content of the QDPS displays is provided to the remote shutdown workstation through the plant information system.

7.5.5 Qualified Data Processing System

The portion of the PMS which is dedicated to providing the safety-related display function is referred to as the QDPS. The QDPS has a redundant configuration consisting of sensors, QDPS hardware, and qualified displays. The QDPS provides postaccident monitoring information to the MCR; the same information can be transmitted to the remote shutdown workstation. The QDPS provides status information on the postaccident Category 1 variables and selected Category 2 or 3 variables, as determined from the function-based task analysis. It also provides a set of system-level displays to support the emergency procedures and aid the operator in implementing function restoration and plant recovery. The QDPS provides the operator with sufficient operational data to safely shut the plant down in the event of a failure of the other display systems.

The QDPS is divided into two separate electrical divisions. Each of the two electrical divisions is connected to a Class 1E dc UPS with sufficient battery capacity to provide electrical power for 72 hours. If all ac power sources are lost for a period of time that exceeds 72 hours, the ancillary diesel generator will energize the power supply system. Instrumentation associated with the primary variables that are energized from the Class 1E dc UPS are powered from one of the two electrical divisions with 72-hour battery capacity. Other variables are energized from those electrical divisions with 24-hour battery capacity.

7.5.6 Bypass and Inoperable Status Information

RG 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems," states that the operator needs to know the operating status of safety-related systems, and the extent to which safety-related systems have been bypassed. The AP1000 design incorporates this information into the alarm system, the operator's workstation, and the wall panel information system in the MCR. High-level plant status during any plant state is continuously available on the wall panel information system. At the operator's workstation, physical and functional displays show how a component's availability or unavailability impacts the alignment and availability of the system. This is indicated on the display that exhibits the bypassed or deliberately induced inoperable protection system, and the systems actuated or controlled by that protection system. Alarms on the operator's workstation and the wall panel information system indicate abnormal conditions. The alarm logic considers improper safety system alignments, safety-related component unavailability, and bypassed protective functions. The alarm system continuously monitors this information.

The following conditions warrant operator awareness in accordance with RG 1.47:

- inoperability of any redundant portion of the reactor protection system, systems actuated or controlled by the reactor protection system, and auxiliary or supporting systems that must be operable for the protection system (and the system it actuates) to perform its safety-related functions
- inoperability expected to occur more frequently than once a year
- inoperability expected to occur when the affected system is normally required to be operable
- manually initiated inoperability

Based on the above discussion, the staff concludes that the AP1000 design conforms to the guidelines of RG 1.47 regarding the indication of operating status, including the bypassed status of safety-related systems. Therefore, the staff concludes that the design is acceptable.

7.5.7 In-Core Instrumentation System

Instead of the traditional movable detector system used in most of the operating PWR plants, the AP1000 plant design includes the IIS, a fixed in-core detector system, to measure in-core neutron flux distribution. The primary function of the IIS is to provide a three-dimensional flux map of the reactor core. This map is used to calibrate neutron detectors employed by the protection and safety monitoring system, as well as to optimize core performance. A secondary function of the in-core instrumentation system is to provide the PMS with the signal necessary for monitoring core exit temperatures.

During plant operation, the in-core instrument thimble assembly is positioned within the fuel assembly and exits through the top of the RV into containment. The fixed in-core detector and core exit thermocouple cables are then routed to different data processing stations. The data are processed and the results are available for display in the MCR.

The in-core instrumentation system data processor receives the transmitted digitized fixed in-core detector signals from the signal processor. It then combines the measured data with analytically derived constants, and certain other plant instrumentation sensor signals, to generate a full, three-dimensional indication of nuclear power distribution in the reactor core. The hardware and software which perform the three-dimensional power distribution calculation are capable of executing the calculation algorithms and constructing graphical and tabular displays of core conditions at intervals of less than 1 minute. The analysis software provides information required to activate a visual alarm display to alert the operator about the current existence of, or the potential for, reactor operating limit violations.

The calculation algorithms are capable of determining the core average axial offset using a set of the total 42 in-core monitor assemblies. A minimum set of in-core monitor assemblies consists of the following:

- 30 operating assemblies, with at least two operating assemblies in each quadrant, prior to nuclear model calibration
- 21 operating assemblies, with at least two operating assemblies in each quadrant, after nuclear model calibration

The nuclear model calibration is performed after each new core load.

Even though the flux mapping function is not considered a safety-related function, the quality of the hardware and software of the IIS needs to be equivalent to that of the PMS because the signal from the IIS is used to calibrate the ex-core nuclear instrumentation input to the overtemperature and overpower reactor trip setpoints. To ensure the quality of the IIS, the ITAAC for the system design process will be applied. DCD Tier 1, Section 2.5.5 provides the design description and design commitment in the ITAAC Table 2.5.5-2. The ITAAC process will verify the design requirements, including the separation provision between Class 1E and non-Class 1E components. The staff finds that the information of the IIS provided in DCD Tier 1 and Tier 2 is acceptable.

7.5.8 Special Monitoring System

The digital metal impact monitoring system is a non-safety-related SMS that monitors the RCS for metallic loose parts. It consists of several active instrument channels, each comprised of a piezoelectric accelerometer (sensor) and signal conditioning and diagnostic equipment. In DCD Tier 2, Section 4.4.6.4, the applicant states that the system's conformance with RG 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors," is described in DCD Tier 2, Section 1.9.1. Section 4.4 of this report addresses the staff's evaluation of this issue. DCD Tier 1, Table 2.5.6-1 provides the design description of the SMS and its associated ITAAC design commitment. DCD Tier 1, Section 2.5.6 provides the design description, including the provision to retrieve the metal impact monitoring data in the MCR, as well as the design commitment, in the ITAAC table. The staff finds that the information concerning the SMS provided in DCD Tier 1 and Tier 2 is acceptable.

7.5.9 Evaluation Findings and Conclusions

The staff conducted a review of the information systems important to safety for conformance with applicable RGs and industry codes and standards. The staff finds that the DCD has adequately classified and identified the guidelines applicable to these systems. Therefore, the staff finds that the requirements of GDC 1 and 10 CFR 50.55a(a)(1) have been met.

The staff's review included the identification of those information systems and components that are important to safety and are designed to survive the effects of earthquakes, other natural phenomena, abnormal environments, and missiles. Based on its review, the staff concludes that the DCD has identified those systems and components consistent with the design bases for these systems. DCD Tier 2, Sections 3.10 and 3.11 address the qualification programs to demonstrate the capability of these systems and components to survive these events. The staff finds that the requirements of GDC 2 and 4 have been met.

The non-safety portions of the information systems are appropriately isolated from safety systems, including the safety portions of the information systems. The staff finds that the isolation of these systems from safety systems satisfies the requirements of 10 CFR 50.55a(h) and GDC 24.

The postaccident monitoring system conforms to the guidelines in RG 1.97 regarding the assessment of plant conditions during and following an accident. The redundant information systems conform to the guidelines for the physical independence of electrical systems provided in RG 1.75. The postaccident monitoring system includes appropriate variables. The range and accuracy of the instrument channels for these variables are consistent with the plant safety analysis. The staff finds that the postmonitoring system meets the requirements of GDC 13 and 19.

The staff reviewed the systems for which a bypassed or inoperable status is indicated in the control room. The staff finds that the bypass indications will give the operators timely information so that they can mitigate the effects of unexpected system unavailability.

Therefore, the bypass indications satisfy the guidelines of RG 1.47. Based on the discussion above, the staff finds that the design meets the applicable requirements of 10 CFR 50.55a(h) and 50.34(f)(2)(v).

The staff concludes that the design of the information systems important to safety is acceptable and meets the relevant requirements of GDC 1, 2, 4, 13, 19, and 24; 10 CFR 50.55a(a)(1); and 10 CFR 50.55a(h).

7.6 Interlock Systems Important to Safety

The areas reviewed in DCD Tier 2, Section 7.6, include those interlock systems that reduce the probability of occurrence of specific events or verify the state of a safety system. These systems include interlocks to prevent overpressurization of low-pressure systems and interlocks to verify availability of safeguard functions.

The staff reviewed the interlock systems to confirm that design considerations, such as redundancy, independence, single failures, qualification, bypasses, status indication, and testing, are consistent with the design bases of these systems and commensurate with the importance of the safety functions to be performed.

7.6.1 Normal Residual Heat Removal System Isolation Valves

An interlock is provided for the motor-operated RNS inner and outer suction isolation valves, which are normally closed. The interlock prevents the RNS suction valves from being opened by operator action unless the RCS pressure is less than a preset pressure and the IRWST suction and discharge valves are in a closed position.

There are two motor-operated valves in series in each of the two parallel paths of the RNS pump suction lines from the RCS hot leg. The two valves near the RCS hot leg are designated as the inner isolation valves, and the two valves near the RNS pumps are designated as the outer isolation valves. The logic for operation of the inner valves and the outer valves is identical. The pressure transmitter used for valve interlocks on the inner valves is diverse from the pressure transmitter used for the outer valve interlocks. These four motor-operated valves are powered from safety-grade 125-volt (V) dc buses. The inner valve is powered by a separate power supply from the outer valve of each series combination. The valves may be closed by operator action from the MCR at any time. During extended normal residual heat removal operations following cooldown, the isolation valves' motor breakers are opened or removed to prevent an inadvertent closure of the valves. Alarms are provided in the MCR and on the remote shutdown workstation to alert the operator if RCS pressure exceeds the RNS design pressure after the valves are opened.

The safety function of the RNS isolation valves is to remain closed (i.e., the interlocks prevent the valves from being opened while the reactor is pressurized). In the unlikely event that two RNS isolation valves are opened at power, the RNS relief valves provide system overpressure protection.

DCD Tier 2, Figure 7.2-1, Sheet 18, provides the isolation valve interlock logic. Because of the possible severity of the consequences of loss of function, the RNS has the following design features:

- The protection system function of RNS isolation is provided by two parallel sets of two valves in series. The interlock components are redundant, with the inner valve powered by a separate power supply from the outer valve in each series combination.
- The pressure interlock signals and logic are tested on line. This test includes the initiating signals for the interlocks from the protection and safety monitoring system cabinets.

The staff finds that the design for RNS isolation satisfies the single-failure criterion and the online testability requirement of IEEE Std 603-1991. Therefore, the design is acceptable.

7.6.2 Interlocks for the Accumulator Isolation Valve and IRWST Discharge Valve

The accumulator isolation and IRWST injection isolation valves are safety-related to retain their pressure boundary and remain in their open position. The accumulator isolation and IRWST injection valve operators are non-safety-related because the valves are not required to change position to mitigate an accident. The TS requires these valves to be open and power locked out whenever these injection paths are required to be available. The TS requires verification every 24 hours that the motor-operated valves are open. It also requires verification every 31 days that power is removed. With power locked out, the MCR and remote shutdown workstation provides redundant valve position indication. A valve position indication and alarm are provided to alert the operator if these valves are mispositioned. In addition, the valves have a confirmatory open signal during an accident. The valves also have an automatic open signal when their close permissive clears during plant startup. The plant control system provides the confirmatory open and automatic open control signals to the valve operator.

These valves are considered to be in "operating bypass" because, if closed, they prevent the associated systems from performing their intended safety functions. IEEE Std 603-1991 requires automatic removal of the operating bypass when the applicable permissives are not met.

The safety analyses in DCD Tier 2, Chapter 15, assume that these valves are not subject to valve mispositioning (prior to an accident) or spurious closure (during an accident). Based on the confirmatory open signals, the TS verification requirements, and conformance with IEEE Std 603-1991, the staff finds the design acceptable.

7.6.3 Core Makeup Tank Cold-Leg Balance Line Isolation Valves

Each CMT has a cold-leg balance line which is provided with a motor-operated isolation valve, which is normally open. The balance line isolation valves may be manually controlled from either the MCR or the remote shutdown workstation. A confirmatory open signal to these valves automatically overrides any bypass features that are provided to allow the balance line isolation valve to be closed for short periods of time. The control circuit has a valve "maintain-closed" actuation function to provide an administratively controlled manual block of the automatic opening of the valve when the pressurizer level is greater than the P-12 interlock. This function allows the valve to be maintained closed if needed for leakage isolation. The maximum permissible time that a CMT cold-leg balance line isolation valve can be closed is specified in the TS. An alarm is actuated when the maintain-closed function is reinstated.

Each valve is interlocked so that the following conditions occur:

- If the maintain-closed actuation has not been manually initiated, the valve opens automatically on receipt of a confirmatory open signal with the control circuit in automatic control or during the manual valve close function.
- The valve opens automatically whenever the pressurizer water level increases above the P-12 interlock and the control circuit is in automatic control.
- The valve cannot be manually closed when a confirmatory open signal is present.

During power and shutdown operations, the CMT cold-leg balance line isolation valve remains open. To prevent an inadvertent closure of the valve, the protection logic cabinet uses redundant output cards.

These normally open, motor-operated valves have alarms indicating valve mispositioning (with regard to their passive core cooling function). The alarm actuates in the MCR and the remote shutdown workstation.

The staff finds that the interlock logic design of the CMT cold-leg balance line isolation valve is consistent with the requirements of IEEE Std 603-1991 for safety-related functions, and therefore is acceptable.

7.6.4 PRHR Heat Exchanger Inlet Isolation Valve

The PRHR heat exchanger inlet line includes a normally open, motor-operated isolation valve that is controlled from the MCR and remote shutdown workstation. This valve opens when a PRHR actuation signal is initiated. This confirmatory signal provides a means to automatically override bypass features (which are provided to allow closure of the valve in order to perform operability testing). The maximum permissible time that the valve can be closed is specified in the TS. This valve cannot be manually closed when a PRHR heat exchanger actuation signal is present.

During plant operation and shutdown, the PRHR heat exchanger inlet valve is open. To prevent an inadvertent closure of the valve, the PMS cabinet uses redundant output cards. Power to the valve is normally locked out while the plant is at power to prevent a fire-induced spurious closing. DCD Tier 2, Figure 7.2-1, Sheet 17 provides the interlock logic of the PRHR isolation valve.

The PRHR isolation valve has an alarm indicating valve misposition. The alarm in the MCR and the remote shutdown workstation actuates under the following conditions:

- Sensors on the motor operator for the valve indicate the valve is not fully open.
- Redundant sensors on the valve stem indicate the valve is not fully open.

The staff finds that the interlock logic design of the PRHR heat exchanger inlet isolation valve is consistent with the requirements of IEEE Std 603-1991 criteria for safety-related functions and therefore is acceptable.

7.6.5 Evaluation Findings and Conclusions

The review of the interlock systems important to safety included the interlocks for the following valves:

- RNS isolation valves to prevent overpressurization of low pressure systems when connected to the primary coolant system

- accumulator isolation valves

- IRWST discharge isolation valves

- CMT cold-leg balance line isolation valves

- PRHR heat exchanger inlet isolation valves

The staff conducted a review of these systems to determine their conformance with the guidelines in the applicable RGs and industry codes and standards. The staff finds that the DCD has adequately identified the guidelines applicable to these systems and has properly classified them. The staff finds that there is reasonable assurance that the systems fully conform to the applicable guidelines. Therefore, the design meets the requirements of GDC 1 and 10 CFR 50.55a(a)(1).

Based on its review of interlock system functions, as set forth above, the staff finds that appropriate interlocks are provided to maintain an appropriate design margin to ensure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of AOOs. Therefore, the staff finds that the interlock systems satisfy the requirements of GDC 10, 15, 16, 33, 34, and 35.

Based on the review of interlock system status information, initiation capabilities, and provisions to support safe shutdown, as set forth above, the staff concludes that the capability of the interlock system to monitor interlocks over the anticipated ranges for normal operation, AOOs, and accident conditions is appropriate to ensure adequate safety. Appropriate controls are provided for interlock initiation and bypass. Based on the discussion above, the staff finds that the design satisfies the requirements of GDC 13 and 19.

The review included the identification of those interlock systems and components that are designed to survive the effects of earthquakes, other natural phenomena, and abnormal environments. Based on the review, the staff finds that these systems satisfy the requirements of GDC 2 and 4.

The staff concludes that the design of the interlock systems is established in accordance with its safety function and is, therefore, acceptable. Hence, the staff concludes that the interlock systems meet the relevant requirements of GDC 1, 2, 4, 10, 13, 15, 16, 19, 33, 34, and 35; 10 CFR 50.55a(a)(1); and 10 CFR 50.55a(h).

7.7 Control and Instrumentation Systems

7.7.1 System Description

The I&C systems reviewed in this section include control systems used for normal operation (i.e., systems that are not relied upon to perform safety functions following AOOs or accidents, but their control processes may affect plant safety). These control systems perform the following normal operating and normal startup/shutdown functions:

- reactor power control
- rod control
- pressurizer pressure control
- pressurizer water level control
- feedwater control
- steam dump control
- rapid power reduction
- defense-in-depth control

In addition, this section addresses the review of the DAS that provides a diverse backup to the protection system and mitigates the consequences of any ATWS events. This section also addresses the review of non-safety-related, defense-in-depth systems that the PRA review determined to be risk-significant. The staff reviewed these systems based on the guidance provided in SECY-94-084 on the RTNSS process.

7.7.1.1 Reactor Power Control System

The reactor power control system performs automatic reactor power control and power distribution control by varying the position of the control rods. Separate control banks are used to regulate reactor power and power distribution. The power control system enables the plant to respond to the load changes for plus or minus 10 percent of a step-load change, ramp load increases and decreases of 5 percent per minute, and grid frequency response resulting in a power change of 2 percent per minute, with a 10 percent maximum. The system also enables daily load-follow operation. These capabilities are accomplished without resulting in a reactor trip or steam dump actuation.

The reactor power control system uses one control subsystem for regulating core power (the M bank) and one control subsystem to regulate axial offset (the AO bank). During load-follow or load-regulation response transients, the power control and the axial offset control subsystems jointly function to control both core power and axial offset. The power control system controls the reactor coolant average temperature by regulating positions of the M control rod bank. The reactor coolant loop average temperatures are determined from hot- and cold-leg measurements in each reactor coolant loop. The programmed coolant temperature increases linearly with turbine load. The temperature input signals are fed from protection channels via isolation devices. Deviation of the reactor coolant temperature from the programmed value is the basic control variable for reactor power control. A separate control strategy is used at low-power levels when the turbine is off line and the steam dump system is used to regulate coolant temperature. In this mode, the operator enters a power level setpoint and a desired rate of change into the setpoint calculator. The nuclear power setpoint calculator then supplies the necessary linear ramp change in core power, at the selected rate, to achieve the new setpoint.

The axial offset control is performed by the axial offset rods. Measurements of axial offset are put into the control system and then compared to an axial offset control "window." When the axial offset error is outside the acceptable control window, the axial offset rods actuate at a fixed speed to recover the axial offset.

To minimize the potential for interactions between the reactor power and the axial offset rod control systems, the reactor power control system takes precedence. If a demand signal exists for movement of the power control rods, the axial offset rods are blocked from moving.

7.7.1.2 Rod Control System

The rod control system receives rod speed and direction signals from the power control system and the axial offset control systems. For power control, the rod speed demand signals vary over the range of 5 to 45 inches per minute (8 to 72 steps per minute). For axial offset control, the rod speed demand signals are fixed at a constant speed of 5 inches per minute (8 steps per minute). Manual control is provided to move a bank in or out at a prescribed fixed speed. In the automatic mode, the rods are withdrawn or inserted within the limits imposed by the control interlocks. The power and axial offset control banks are the only rods that can be manipulated under automatic control.

The three shutdown banks are always in the fully withdrawn position during normal operation and are moved to this position at a constant speed by manual control before criticality occurs. A reactor trip causes the banks to fall by gravity into the core.

The variable speed rod drive programmer, used in the power control system, inserts small amounts of reactivity at low speed. This permits fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing controls at high speed for transients, such as load rejections.

The digital rod position indication system measures the position of each rod using a detector consisting of discrete coils mounted concentrically with the rod drive pressure housing. The coils are located axially along the pressure housing and magnetically sense the entry and presence of the rod drive shaft through its center line. The demand position system counts the pulses generated in the rod drive control system and provides a digital readout of the demanded bank position. The demanded and measured rod positions are displayed in the MCR. An audible alarm is generated whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. Alarms are also generated if any shutdown rod is detected to have left its fully withdrawn position, or if any M bank control rods are detected at the bottom position, except as part of the normal insertion sequence. The control bank rod insertion alarms and interlocks provide warning to the operator of excessive rod insertion and the need to terminate the insertion.

Rod stops are provided to prevent abnormal power conditions that could result from excessive control rod withdrawal initiated by either a control system malfunction or violation of administrative procedures by an operator.

7.7.1.3 Pressurizer Pressure Control

Pressurizer pressure control is designed to provide stable and accurate control of the primary system pressure to its predetermined setpoint. During steady-state operating conditions, the pressurizer heater output is regulated to compensate for pressurizer heat loss and a small continuous pressurizer spray. During normal transient operation, pressurizer pressure is regulated to provide an adequate margin to limit the actuation of unnecessary safety systems or a reactor trip.

Small or slowly varying changes in pressure are regulated by modulation of the variable heater control. Decreases in pressure larger than that which can be accommodated by the variable heater control result in the actuation of the backup heaters, as does a large increase in the pressurizer water level. Pressure increases that are too fast to be handled by reducing the variable heater output result in pressurizer spray actuation. Spray continues until pressure decreases to the point that the variable heater alone is capable of regulating pressure. For normal transients, including a full-load rejection, the pressurizer pressure control system acts promptly to prevent reaching the high pressurizer pressure reactor trip setpoint.

7.7.1.4 Pressurizer Water Level Control

Pressurizer water level control provides stable and accurate control of the pressurizer level within a prescribed deadband around a programmed value. As the RCS temperature is increased from zero-load to full-load value, the RCS fluid volume expands. The pressurizer level is programmed to absorb this change. A deadband is provided around the pressurizer level program to intermittently control charging and letdown. When the pressurizer level reaches the lower limit of the deadband, the charging system is actuated. This system continues to operate until the pressurizer level is restored to a limit above the nominal programmed value. When the level reaches the upper limit of the deadband, letdown to the liquid waste processing system is actuated. Automatic pressurizer level control is supplied from the point in the startup cycle where the zero-load level is established up through 100-percent power.

7.7.1.5 Feedwater Control

Two modes of feedwater control are incorporated in the feedwater control system:

(1) In the high-power control mode, feedwater flow is regulated in response to changes in steam flow and proportional plus integral steam generator narrow-range level deviation from a preestablished setpoint.

(2) In the low-power control mode, feedwater flow is regulated in response to changes in steam generator wide-range water level and proportional plus integral steam generator narrow-range level deviation from the preestablished setpoint.

A separate low-range feedwater flow measurement is used in the low-power feedwater control mode. The transition from the low-power to the high-power control mode is initiated when the transition point is low enough to allow effective feed-forward control using the wide-range level. In the high-power control mode, feedwater flow indication is provided within the upper limit of the low-range feedwater flow measurement instrument. Tracking of SG level deviation is provided to allow a smooth transition between control modes, as well as between manual and automatic control.

7.7.1.6 Steam Dump Control

The AP1000 has a design objective to sustain a 100-percent load rejection, or a turbine trip from 100-percent power, without generating a reactor trip, requiring atmospheric steam relief, or opening a pressurizer or SG safety valve. The automatic steam dump control system, in conjunction with the rapid power reduction system, is provided to accommodate this abnormal load rejection and to reduce the effects of the transient imposed on the RCS. The steam dump system is sized to pass 40 percent of the total nominal steam flow. This capacity is sufficient to handle reactor trips from any power level, turbine trips from 50-percent power or less, or load rejections of 50 percent or less.

The steam dump control system has two modes of operation:

- The T_{avg} mode uses the difference between measured auctioneered loop T_{avg} and a reference temperature derived from turbine first-stage impulse pressure to generate a steam dump demand signal. This mode is used for at-power transients requiring steam dump.

- The pressure mode uses the difference between measured steam header pressure and a pressure setpoint to generate a steam dump demand signal. This mode is used for low-power conditions and for plant cooldown.

The load-rejection steam dump controller prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is the difference between the lead-lag compensated selected T_{avg} and the selected reference T_{avg} (designated T_{ref}), based on the pressure of the turbine impulse chamber. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase. This generates an immediate demand signal for steam dump. Following the opening of the steam dump valve, the control rods insert in a normal controlled manner to reduce the reactor power to match the turbine load. For a reactor trip situation, the load rejection steam dump controller is defeated and the plant steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead-lag compensated auctioneered T_{avg} and the no-load reference T_{avg}. When the error signal exceeds a predetermined setpoint, the dump valves are opened in a prescribed sequence.

The steam header pressure control mode is manually selected by the operator. The pressure setpoint is manually adjusted based on the desired RCS temperature. The controller also has a feature that allows for automatically controlled plant cooldowns at a chosen rate (within limits). The operator can enter the desired cooldown rate and the desired targeted RCS temperature. The control system then dumps the required steam to achieve the setpoint cooldown rate, and the cooldown stops at the target RCS temperature setpoint.

7.7.1.7 Rapid Power Reduction

The rapid power reduction system reduces nuclear power to a level capable of being handled by the steam dump system for a large-load rejection. When a large and rapid turbine load rejection (via a lead-lag circuit) is detected, the circuit provides a signal demanding the release of a preselected number of control rods. Dropping these preselected rods causes the reactor power to rapidly reduce to approximately 50-percent power. The large-load rejection also actuates the steam dump system and the power control system via a primary-to-secondary power mismatch signal. Following the initial opening, the steam dump valves modulate closed based upon the (T_{avg} - T_{ref}) signal.

Controlled rod insertion and steam dump modulation continues until power is reduced to approximately 15-percent power. The plant stabilizes with the steam dump maintained to match the steam flow to the thermal load. The operators can then switch to the pressure mode of control on the steam dump system, recover the released rods, and establish normal rod control. A normal power escalation can then be performed.

7.7.2 Diverse Actuation System

The DAS is a non-safety-related system that provides diverse backup to the protection system. The applicant stated that this backup is included to support the AP1000 risk goals by reducing the probability of a severe accident as a result of the coincidence of postulated transients and a postulated common-mode failure in the protection and control systems. The specific functions performed by the DAS are selected based on the PRA evaluation. The DAS provides automatic actuation signals, manual actuation signals, and indications for the plant operators. These signals are generated in a functionally diverse manner from the protection system actuation signals. The common-mode failure of sensors of a similar design is also considered in the selection of these functions.

The DAS automatic actuation is accomplished by a microprocessor-based system. Diversity from the PMS is achieved by using a different architecture, different hardware implementation, and different software. Software diversity is achieved by running different operating systems and programming in a different language. The DAS is subject to the following automatic actuations:

- trip of the control rods via the motor-generator set, trip of the turbine, actuation of the core makeup tanks, trip of the reactor coolant pumps, and initiation of the PRHR system upon a low wide-range steam generator level
- initiation of the PRHR system and closure of the IRWST gutter isolation valves upon high hot-leg temperature
- trip of the control rods via the motor-generator set, trip of the turbine, actuation of the core makeup tanks, and trip of the reactor coolant pumps upon low pressurizer water level
- isolation of selected containment penetration and initiation of passive containment cooling water flow upon high containment temperature

The selection of setpoints and time responses is determined so that the DAS automatic functions do not actuate unless the protection system has failed to actuate to control plant conditions. The DAS automatic logic combines the signals from two redundant subsystems in a two-out-of-two logic. The two-out-of-two logic is implemented by connecting the final actuation devices in series. Actuation signals are output to the loads in the form of normally deenergized, energize-to-actuate contacts, with a nominal voltage of 120-v ac or 125-v dc. The use of the normally deenergized output state, along with the dual, two-out-of-two logic, reduces the probability of inadvertent actuation.

The manual actuation of the DAS is implemented by wiring the controls located in the MCR directly to the final loads in a way that completely bypasses the normal path through the control board multiplexers, the PMS cabinets, and the DAS automatic logic. The diverse manual functions are as follows:

- reactor and turbine trip
- PRHR actuation and close IRWST gutter isolation valves
- CMT actuation and RCP trip
- ADS valve actuation (Stages 1, 2, 3, and 4)
- passive containment cooling actuation
- critical containment penetration isolation
- containment hydrogen ignitor actuation

- IRWST injection initiation
- containment recirculation initiation
- IRWST drain to containment initiation

To support the diverse manual actuations, sensor outputs are displayed in the MCR that are diverse from the protection system display functions. The following indications are provided from at least two sensors per function:

- wide-range steam generator water level for reactor trip and PRHR actuations, and for overfill prevention by manual actuation of the ADS valves

- hot-leg temperature for PRHR

- core exit temperature for ADS actuation, subsequent initiation of IRWST injection, and containment hydrogen igniter actuation

- pressurizer level for CMT actuation and reactor coolant pump trip

- containment temperature for containment isolation and passive containment cooling system actuation

The DAS uses sensors that are separate from those being used by the PMS and the PLS. This prevents failures from propagating to the other plant systems through the shared sensors. A signal isolation exists between the two subsystems within the DAS, one for each input and output path. These isolators are characterized by a high common-mode voltage withstand capability to provide the necessary isolation against faults propagation among the DAS subsystems. Actuation interfaces are shared between the DAS and the PMS. The DAS actuation devices are isolated from the PMS actuation devices, so as to avoid adverse interactions between two systems. The actuation devices of each system are capable of independent operation that is not affected by the operation of the other. The DAS and the PMS use independent and separate uninterruptible power supplies. This type of interface prevents the failure of an actuation device in one system from propagating a failure to the other system. The DAS is designed to actuate components only in a manner that initiates the safety function. The DAS is designed so that, once actuated, the mitigation action goes to completion, and the subsequent return to operation requires deliberate operator action.

As stated in the AP1000 PRA, the DAS is needed to mitigate ATWS events. For Westinghouse plants, the ATWS rule (10 CFR 50.62) requires diverse actuation of auxiliary feedwater and turbine trip. The DAS provides for the ATWS protection features mandated for the applicant's plants plus a diverse reactor scram. As discussed in Section 7.1.6 of this report, the DAS is also identified as the system designed to meet the Commission-approved position on I&C system defense-in-depth and diversity. The DAS performs the same functions as the PMS for accident mitigation when a postulated common-mode failure disables the PMS.

DCD Tier 1, Section 2.5.1, "Diverse Actuation System," provides a design description and design commitment in the ITAAC Table 2.5.1-4. On the basis of its review of the information stated above, the staff finds that the DAS design meets the requirements of the defense-in-depth position. The design process described in DCD Tier 1, Section 2.5.1, has provided reasonable assurance that the DAS will meet quality standards. Therefore, the DAS is acceptable.

7.7.3 Signal Selector Algorithms

Signal selector algorithms provide the plant control system with the ability to obtain inputs from the PMS. Each signal selector algorithm receives data from each of the redundant divisions of the PMS. The data are received from each division through an isolation device. The signal selector algorithms select those protection system signals that represent the actual status of the plant and reject erroneous signals. Thus, the control system does not cause an unsafe control action to occur, even if one of the four redundant protection channels is degraded by random failure simultaneous with another of the four channels being bypassed for test or maintenance.

The signal selector algorithms provide validated process values to the plant control system. They also provide the validation status, the average of the validated process values, the number of validated process values, and alarms (if one process value has been rejected). For the logic values received from the PMS, such as permissive, the signal selector algorithms perform voting on the logic values to provide a valid logic value to the plant control system.

The staff concludes that implementing signal selector algorithms in the plant control system design will improve the reliability of the control system and minimize challenges to the protection systems. Therefore, the staff concludes that the signal selector algorithms design is acceptable.

7.7.4 Evaluation Findings and Conclusions

The staff conducted a review of these systems to evaluate their conformance with the guidelines in the applicable RGs and industry codes and standards. The staff finds that the DCD has adequately classified and identified the guidelines applicable to these systems. The staff finds that the control systems are appropriately designed and are of sufficient quality to minimize the potential for challenges to the safety systems. Based on the review of the conformance of the system design with the guidelines, the staff finds that there is reasonable assurance that the systems fully conform to the guidelines applicable to these systems. Therefore, the staff finds that the requirements of GDC 1 and 10 CFR 50.55a(a)(1) have been met.

The control systems that are used for normal operation are not relied upon to perform safety functions, but to control plant processes having a significant impact on plant safety. These control systems include the reactivity control systems, as well as control systems for primary and secondary coolant flow. The staff's review of the control systems included features of these systems for both manual and automatic control of non-safety-related process systems. The staff concludes that the control systems permit actions to be taken to operate the plant safely during normal operation, including operational occurrences. The staff finds that the control systems satisfy the requirements of GDC 13 and 19.

Isolation devices are used in the AP1000 I&C system design to maintain the electrical independence of divisions, and to prevent interaction between non-safety-related systems and the safety-related system. Isolation devices are incorporated into selected interconnections to maintain division independence. Isolation devices serve to prevent credible faults in one circuit from propagating. On the basis of its review, the staff further concludes that the isolation between control and protection systems meets the guidelines of IEEE Std 603-1991 as endorsed in RG 1.153. Therefore, the design also meets the requirements of 10 CFR 50.55a(h) and GDC 24 for assurance of safety functions in the event of control system failure.

The conclusions of the analysis of AOOs and accidents, as presented in DCD Tier 2, Chapter 15, have been used to confirm that plant safety is not dependent upon the response of the control systems. The staff also confirmed that failure of the control systems themselves, or as a consequence of supporting system failure, such as loss of power sources, does not result in plant conditions more severe than those described in the analysis of design-basis accidents and AOOs.

The staff concludes that the design of the control systems is acceptable and meets the relevant requirements of GDC 1, 13, 19, and 24; 10 CFR 50.55a(a)(1); and 10 CFR 50.55a(h).

8. ELECTRIC POWER SYSTEMS

8.1 Introduction

The AP1000 design as presented does not require Class 1E alternating current (ac) electrical power, except that provided by the Class 1E direct current (dc) batteries and their inverters, to accomplish the plant's safety-related functions.

As the bases for evaluating the adequacy of the design of the Class 1E dc batteries and their inverters, to accomplish the plant's safety-related functions as presented in AP1000 Design Control Document (DCD) Tier 2, Chapter 8, "Electric Power," the U.S. Nuclear Regulatory Commission (the NRC or staff) used the acceptance criteria and guidelines for electric power systems contained in Chapter 8, "Electric Power," of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants—LWR Edition" (SRP); Regulatory Guide (RG) 1.153, "Criteria for Safety Systems"; RG 1.155, "Station Blackout"; and Section 50.63 of Title 10 of the Code of Federal Regulations (CFR), "Loss of All Alternating Current Power." Although these guidelines pertain to Class 1E equipment, the staff considered them in its review of the overall adequacy of the Westinghouse AP1000 simplified passive advanced light-water reactor (ALWR) electric power systems.

In SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs," the NRC set forth policy regarding those systems in passive light-water reactors that are designated non-safety-related, but that may have a significant role in accident and consequence mitigation. Section 8.5.2.3 of this report discusses the specific aspects of electric power systems that are designated as RTNSS.

8.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The staff's review covers the information, analyses, and documents for the offsite power system and the stability studies for the electrical transmission grid. The review focuses on the basic requirement that the loss of the nuclear unit, which is the largest operating unit on the grid, or the loss of the most critical transmission line will not result in the loss of offsite power to the plant. SRP Branch Technical Position (BTP) Instrumentation and Control Systems Branch (ICSB)-11, "Stability of Offsite Power Systems," and General Design Criteria (GDC) 17, "Electric Power Systems," of 10 CFR Part 50 outline an acceptable approach to addressing the issue of stability of offsite power systems. Specific review criteria are contained in SRP Section 8.1, "Electric Power," SRP Section 8.2, "Offsite Power System," Appendix A to SRP Section 8.2, BTP Power Systems Branch (PSB)-1, "Adequacy of Station Electric Distribution System Voltages," and ICSB-11.

Technical Evaluation

The staff consulted the guidance documents specified in Section 8.1 of this report. Additional considerations pertain to the non-Class 1E portion of the electrical design with respect to RTNSS. See Section 8.5.2.3 of this report for a discussion regarding RTNSS.

The applicant shares the AP1000 design responsibility for the offsite power system with the combined license (COL) applicant referencing the design. The requirements imposed on the COL applicant's design by the AP1000 design are specified by interface requirements or COL action items. See Section 8.2.3 of this report for a discussion of COL action items.

8.2.1 Offsite Circuits Outside the AP1000 Scope of Design

The utility company grid system and its interconnection to other grid systems and generating stations are site specific. Section 8.2.3 of this report discusses specific COL action items with respect to this subject area.

8.2.2 Offsite Circuits within the AP1000 Scope of Design

The AP1000 electrical system design scope encompasses the plant from the high side of the main power transformer, and from the high side of the reserve auxiliary transformer (provided for maintenance).

The main generator normally provides power to the main ac power system. When the main generator is not available, the generator output breaker is opened and the plant auxiliary power comes from the switchyard by backfeeding through the main step-up transformers and the unit auxiliary transformers (UAT). In addition, two non-Class 1E onsite standby diesel generators supply power to selected loads in the event of loss of either the main generator or the main transformer. There is also a maintenance source provided through a reserve auxiliary transformer (RAT). The maintenance source is site specific, and bus transfer to the maintenance source is manual. Maintenance power is provided at the medium voltage level of 6.9 kilovolts (kV).

The main generator is connected to the offsite power system by three single-phase, main step-up transformers. The generator buses provide the normal power source for the plant auxiliary ac loads through two unit auxiliary transformers of identical rating. In the event of a loss of the main generator, an auto-trip of the main generator breaker maintains the power without interruption from the preferred power supply. The power then flows from the switchyard to the auxiliary loads through the main and unit auxiliary transformers. A spare single-phase, main transformer is provided, and it can be placed in service upon failure of one phase of the main step-up transformers.

The staff considers that the information provided is sufficient and is therefore acceptable.

8.2.3 Offsite Power System Interfaces

The operating voltage for the high side of the AP1000 transformer and transmission switchyard, as well as the frequency decay rate, are site specific and, therefore, will be addressed in the COL application. The staff will provide further review of the operating voltage and the frequency decay rate when a COL applicant submits its application. This COL information is discussed in DCD Tier 2, Section 8.2.5, "Combined License Information for Offsite Electrical

Power," and in Item 8.3 of DCD Tier 2, Table 1.8-1, "Summary of AP1000 Plant Interfaces with Remainder of Plant." Therefore, the operating voltage and the frequency decay rate is COL Action Item 8.2.3-1.

8.2.3.1 Grid Stability

The AP1000 is designed with passive safety-related systems for core cooling and containment integrity and, therefore, does not depend on the electric power grid for safe operation. This feature of the AP1000 design significantly reduces the importance of grid connection and grid stability. The AP1000 safety analyses assume that the reactor coolant pumps (RCPs) can receive power at 6.9 kV from either the main generator or the grid for a minimum of 3 seconds following a turbine trip. The AP1000 design has a generator circuit breaker on the output of the main generator and utilizes backfeed from the grid to maintain power to the RCPs following a turbine/generator trip.

If during power operation of the plant, a turbine trip occurs, the motive power to the turbine will be removed. The generator will keep the shaft rotating at synchronous speed (governed by the grid frequency) by acting like a synchronous motor. The reverse power relay, which monitors generator power, will sense this condition and, after a time delay of at least 15 seconds, open the generator breaker. During this time delay, the generator will provide voltage support to the grid, if needed. The RCPs will receive power from the grid for at least 3 seconds following a turbine trip.

The COL applicant will perform a grid stability analysis to show that the grid will stay stable and that the RCP bus voltage will remain above the voltage required to maintain the flow assumed in DCD Tier 2, Chapter 15, "Accident Analyses," for a minimum of 3 seconds following a turbine trip. This COL information is discussed in DCD Tier 2, Section 8.2.5, "Combined License Information for Offsite Electrical Power," and in Item 8.3 of DCD Tier 2, Table 1.8-1, "Summary of AP1000 Plant Interfaces with Remainder of Plant." This is COL Action Item 8.2.3.1-1.

The COL applicant will set the protective devices controlling the switchyard breakers in such a way as to preserve the grid connection following a turbine trip. This COL information is discussed in DCD Tier 2, Section 8.2.5, "Combined License Information for Offsite Electrical Power," and in Item 8.3 of DCD Tier 2, Table 1.8-1, "Summary of AP1000 Plant Interfaces with Remainder of Plant." This is COL Action Item 8.2.3.1-2.

If the turbine trip occurs when the grid is not connected (generator supplying house loads only), the main turbine generator shaft will begin to slow down as the energy stored in the rotational inertia of the shaft is used to supply the house loads (including the RCPs). The system will coast down until the generator exciter can no longer maintain generator terminal voltage and the generator breaker is tripped based on either generator undervoltage or exciter overcurrent. The coastdown will last at least 3 seconds before the generator breaker trips.

The sequence of events following a loss of offsite power is the same as that described for grid disconnected operation. The sequence of events provides additional assurance that the main generator will be available to support grid voltage, if needed, for the 3 seconds assumed in the DCD Tier 2, Chapter 15 analysis.

Because of certain electrical failures (such as a loss of isophase bus), power from the generator or grid may not be available to the RCPs for a minimum of 3 seconds following a turbine trip. The COL applicant must perform a failure modes and effects analysis (FMEA) to ensure that the design provides power to the RCPs for a minimum of 3 seconds following a turbine trip. If the power to the RCPs cannot be maintained for 3 seconds, then the DCD Tier 2, Chapter 15 analysis should be reanalyzed and provided to the staff for review. Open Item 8.2.3.1-1 in the Draft Safety Evaluation Report (DSER) identified the need for inclusion of this COL information in the DCD.

The applicant provided a response to DSER Open Item 8.2.3.1-1 by letter dated July 31, 2003. The response stated that the isophase bus is a passive component that must be operational for the turbine generator to be operated. Because the isophase bus is required for power operation, it is known to be operational at the start of the 3-second time period. The failure of a passive component that is known to be initially operational within a 3-second window is a very low probability event. The applicant revised DCD Tier 2, Section 8.2.2 to state the following:

> The Combined License applicant will perform a grid stability analysis to show that, with no electrical system failures, the grid will remain stable and the reactor coolant pump bus voltage will remain above the voltage required to maintain the flow assumed in the Chapter 15 analyses for a minimum of 3 seconds following a turbine trip. In the Chapter 15 analyses, if the initiating event is an electrical system failure (such as failure of the Isophase bus), the analyses do not assume operation of the reactor coolant pumps following the turbine trip.

This is COL Action Item 8.2.3.1-3.

The staff concludes that the electrical features described in the AP1000 DCD can provide power, assuming no electrical system failures, either from the main generator or from the grid, to the RCPs following a turbine trip for a minimum of 3 seconds. However, for those initiating events involving electrical system failures, the analyses do not assume operation of the RCPs following a turbine trip and therefore the availability of power to the RCPs is not a concern. The staff has evaluated the applicant's response and the modifications in the DCD and concludes that the applicant has adequately addressed Open Item 8.2.3.1-1 and, therefore, the open item is resolved.

8.2.3.2 <u>Conformance to Criteria (Part Exemption from GDC 17 for AC Offsite Power Sources)</u>

The AP1000 design does not require ac power sources to mitigate design-basis events. Although the AP1000 is designed with reliable non-safety-related offsite and onsite ac power sources that are normally expected to be available for important plant functions, non-safety-related ac power is not relied upon to maintain core cooling or containment integrity. DCD Tier 2, Section 3.1, "Conformance with Nuclear Regulatory Commission General Design Criteria," states that the AP1000 design supports an exemption to the requirements of GDC 17, for two physically independent offsite circuits, by providing safety-related passive safety systems for core cooling and containment integrity.

A reliable dc power source supplied by batteries provides power for the safety-related valves and instrumentation during transient and accident conditions. The Class 1E dc and uninterruptible power supply (UPS) system is the only safety-related power source required to monitor and actuate the safety-related passive systems. Otherwise, the plant is designed to maintain core cooling and containment integrity, independent of non-safety-related ac power sources indefinitely. The non-safety ac power system is designed such that plant auxiliaries can be powered from the grid under all modes of operation. During loss of offsite power (LOOP), ac power is supplied by the onsite standby diesel generators. The onsite standby power system is not required for safe shutdown of the plant.

Pursuant to 10 CFR 52.48, "Standards for review of applications," applications filed under this subpart will be reviewed for compliance with the standards set out in 10 CFR Part 20, Part 50 and its appendices, and Parts 73 and 100 as they apply to applications for construction permits and operating licenses for nuclear power plants, and as those standards are technically relevant to the design proposed for the facility. The requirements of GDC 17 are set forth in Appendix A to Part 50.

Pursuant to 10 CFR 50.12, "Specific Exemption," the Commission may, upon application by any interested person or upon its own initiative, grant exemptions from the requirements of 10 CFR Part 50 when (1) the exemptions are authorized by law, will not present an undue risk to public health or safety, and are consistent with the common defense and security; and (2) when special circumstances are present. Special circumstances are present whenever, according to 10 CFR 50.12(a)(2)(ii), "Application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule."

The underlying purpose of the requirement of GDC 17 to provide two offsite power sources to the plant is to ensure sufficient power to accomplish safety functions. The AP1000 design does not rely on power from the offsite system to accomplish safety functions, and therefore, the underlying purpose of the rule is met without the need for two independent offsite circuits. The staff concludes that special circumstances exist, in that, the regulation need not be applied in this particular circumstance to achieve the underlying purpose of having two offsite power sources. This meets the requirements for an exemption to GDC 17, as described in 10 CFR 50.12. Therefore, the staff concludes that an exemption to the requirements of GDC 17 for two physically independent offsite circuits is justified.

8.2.3.3 <u>Testing and Inspection of the Offsite Power System</u>

GDC 18, "Inspection and Testing of Electric Power Systems," requires that electric power systems important to safety shall be designed with the following capabilities:

- the ability to permit appropriate periodic inspection and testing of important areas and features (such as wiring, insulation, connections, and switchboards) to assess the continuity of the systems and the condition of their components

- the ability to periodically test the operability and functional performance of the components of the systems

- the ability to periodically test the operability of the systems as a whole (under conditions as close to design as practical) and the full operation sequence that brings the systems into operation

DCD Tier 2, Section 8.2.5 states that the COL applicants referencing the AP1000 certified design will address the design of the ac power transmission system and its testing and inspection plan. The testing and inspection capability of the system will provide conformance with GDC 18. This is COL Action Item 8.2.3.3-1.

8.2.3.4 Specific Interface Requirements for Supporting Chapter 15 Analyses

In the case of events involving a turbine trip, the applicant assumes that a LOOP, and the resulting coastdown of the RCPs, occurs 3 seconds after the turbine trip. The basis for the 3-second delay is provided in DCD Tier 2, Section 8.2, "Offsite Power System." This section describes the electrical design features of the AP1000, the electrical system response to a turbine trip, and the COL applicant interfaces that support the 3-second assumption. The AP1000 design provisions include the following electrical features that support the 3-second delay:

- An output generator circuit breaker and reverse power relay, with at least a 15-second delay before tripping the breaker following a turbine trip, will be used. This allows the generator to provide voltage support to the grid and maintain adequate voltage to the RCPs for significantly longer than the assumed 3 seconds.

- COL applicant interface Item 8.3 in DCD Tier 2, Table 1.8-1 states that transient stability must be maintained and the RCP bus voltage must stay above the voltage required to maintain the flow assumed in DCD Tier 2, Chapter 15 analyses for a minimum of 3 seconds following a turbine trip. This ensures that, for Westinghouse's unique grid system configuration, a grid instability condition following a turbine trip will take at least 3 seconds to result in a loss of power to the RCPs.

- COL applicant interface Item 8.3 in DCD Tier 2, Table 1.8-1 states that the protective devices controlling the switchyard breakers are set with consideration for preserving the plant grid connection following a turbine trip. This is especially important in generator output circuit breaker designs to ensure that the backfeed offsite circuit, through the generator main stepup transformer, is not interrupted by opening of the switchyard breakers following a turbine trip.

- No automatic transfers of RCP buses are used in the design (this precludes bus transfer failures following a turbine trip).

- If a turbine trip occurs when the grid is not connected to the plant, the main generator will be available to power the RCPs for at least 3 seconds before the generator output breaker is tripped based on either generator undervoltage or exciter overcurrent.

The staff concludes that the electrical features described in the AP1000 DCD can provide power to the RCPs following a turbine trip for a minimum of 3 seconds, either from the main generator or from the grid.

8.2.3.5 Conclusions

With respect to the offsite power system interfaces, the staff considers the applicant's description to be acceptable on the basis that sufficient information is provided for the scope of the offsite circuit. Further, pursuant to 10 CFR 50.12, the staff considers acceptable an exemption to the requirements of GDC 17 concerning the need for two offsite power sources. Therefore, the staff concludes that the design of the offsite power system for the AP1000 is acceptable.

8.3 Onsite Power Systems

8.3.1 AC Onsite Power System

Regulatory Evaluation

The onsite ac power system is a non-Class 1E system that provides reliable ac power to the various system electrical loads. It does not perform any safety-related functions. These loads enhance an orderly shutdown under emergency (not accident) conditions. Additional loads for investment protection can be manually loaded on the standby power supplied. The staff's review covers the descriptive information, analyses, and referenced documents for the ac onsite power system, as well as the applicable recommendations from NUREG/CR-0660, "Enhancement of On-site Emergency Diesel Generator Reliability."

Technical Evaluation

The main onsite ac power system is a non-Class 1E system which does not perform any safety-related function. During power generation mode, the turbine generator normally supplies electric power to the plant auxiliary loads through UATs. The plant is designed to sustain a load rejection from 100 percent power, with the turbine generator supplying the plant house loads.

During plant startup, shutdown, and maintenance, the generator breaker is opened. Under this condition, the main ac power is provided by the preferred power supply system from the high voltage switchyard (switchyard voltage is site specific) through the main step-up transformers and two UATs. Each UAT supplies power to about 50 percent of the plant loads. The UATs have two identically rated 6.9 kV secondary windings.

The maintenance source and the associated RAT primary voltage, are site specific. The RAT is sized to replace any one of the UATs, if needed. The availability of the RAT, provides operational flexibility if any of the UATs are out of service.

The buses tagged with odd numbers (ES1, ES3, etc.) are connected to one UAT, while the buses tagged with even numbers (ES2, ES4, etc.) are connected to the other UAT. These 6.9 kV buses are provided with access to the maintenance source through normally open circuit breakers connecting the bus to the RAT. Bus transfer to the maintenance source is manual.

The arrangement of the 6.9 kV buses permits feeding functionally redundant pumps or groups of loads from separate buses, and enhances the plant's operational flexibility. The RCPs are powered from the four 6.9 kV switchgear buses (ES3, ES4, ES5, and ES6) located in the turbine building. Each bus powers one RCP. Variable speed drives are provided for RCP startup and operation when the RCP temperature is less than 232.2 °C (450 °F). During normal power operation, with RCP temperatures above 232.2 °C (450 °F), 60 Hertz (Hz) power is provided directly to the RCPs, and the variable-speed drives are not connected. Each RCP is powered through two Class 1E circuit breakers connected in series. These are the only Class 1E circuit breakers used in the main ac power system for the specific purpose of satisfying the safety-related tripping requirement of these pumps. These Class 1E breakers assure that the RCPs trip during accident scenarios. The control power for each RCP trip circuit is provided by its respective Class 1E 125 Vdc system.

The staff considers that the information provided is sufficient and is therefore acceptable.

8.3.1.1 Electric Circuit Protection

The major types of protection systems employed for AP1000 include the following:

Medium Voltage Switchgear

Each medium voltage switchgear bus is provided with a bus differential relay (device 87B) to protect against a bus fault. The actuation of this relay initiates tripping of the source incoming circuit breaker and all branch circuit load breakers. The differential protection scheme employs high speed relays. Motors rated 1500 kilovoltampere (kVA) (1500 horsepower [hp]) and above are generally provided with a high dropout overcurrent relay (device 50D) for differential protection.

To provide the backup protection for the buses, the source incoming circuit breakers are equipped with an inverse time overcurrent relay on each phase and an inverse time ground fault relay for bus protection. Each medium voltage motor feeder breaker is equipped with a motor protection relay, which provides protection against various types of faults (phase and ground) and abnormal conditions such as locked rotor and phase unbalance. Each medium voltage power feeder to a 480 volt (V) load center has short circuit, overload, and an overcurrent protection for ground fault.

Medium voltage buses are provided with a set of three undervoltage relays (27B) that trip feeder circuit breakers connected to the bus upon a complete loss of ac power, using two-out-of-three logic, to prevent spurious actuation. In addition, another set of undervoltage relays is provided on the line side of the incoming supply breakers of buses ES1 and ES2. These relays initiate an alarm in the main control room (MCR) if a sustained low- or high-voltage condition occurs.

Medium voltage switchgears (ES1 and ES2) are located in the electrical switchgear rooms 1 and 2 of the annex building. Switchgears ES3, ES4, ES5, and ES6 are located in the turbine building electrical room. The Class 1E medium voltage switchgear for four RCPs is located in the turbine building. The control power for each RCP trip circuit is provided by its respective Class 1E 125 Vdc system.

480 V Load Centers

Each motor feeder breaker in load centers is equipped with a trip unit, which has long-time, instantaneous, and ground fault tripping features. Each load center bus has an undervoltage relay that initiates an alarm in the MCR upon loss of bus voltage.

480 V Motor Control Center

Motor control center (MCC) feeders for low voltage (460 V) motors have molded case circuit breakers (magnetic or motor circuit protectors) and motor starters. These motor starters are provided with thermal overload protection. Non-Class 1E ac motor-operated valves are protected by thermal overload devices.

The applicant has addressed the major types of electric circuit protection systems and has provided sufficient information.

8.3.1.2 Standby Diesel Generators

The onsite standby power system, powered by the two onsite standby diesel generators, provide 4000 kilowatts (kW) each to selected loads in the event of a loss of normal and preferred ac power supplies. The system's function is to provide a backup source of electrical power to onsite equipment needed to support the decay heat removal operation during reduced reactor coolant system inventory and midloop operation. Those loads, which are priority loads for the defense-in-depth function based on their specific functions (permanent, non-safety loads), are assigned to annex building buses ES1 and ES2. These permanent, non-safety loads are divided into two functionally redundant load groups.

Separate sources provide power supplies to each diesel generator subsystem component to maintain reliability and operability of the onsite standby power system. The source incoming breakers on switchgear ES1 and ES2 are interlocked to prevent inadvertent connection of the onsite standby diesel generator and preferred/maintenance ac power sources to the 6.9 kV buses at the same time. The diesel generator, however, is capable of being manually paralleled with the preferred power supply for periodic testing. Design provisions protect the diesel generators from excessive loading, beyond the design maximum rating, should the preferred power be lost during periodic testing. The control scheme, while protecting the diesel generators from excessive loading, does not compromise the onsite power supply's ability to support the defense-in-depth loads. The standby diesel generators are included in the investment protection short-term availability controls.

If a loss of the preferred power source occurs concurrently with the turbine-generator trip, the diesel generators are automatically started and connected to the associated medium voltage buses, should these buses experience a loss of voltage. The following conditions are prerequisites for the diesel generator automatic start:

- starting air pressure within acceptable limits
- dc control power availability for fuel oil valve solenoid operation and the starting air motor solenoid
- fuel supply availability
- diesel generator controls in the automatic mode
- diesel generator breaker lockout trip permissive not activated by any of the trouble conditions
- *engine prelubrication provided*

Satisfactory status of these "prestart" conditions continuously monitored, and any failure will be annunciated in the MCR.

The starting air subsystem consists of an ac motor-driven, air-cooled compressor and an air receiver with sufficient stored capacity for three diesel engine starts. The diesel generator engine fuel oil system consists of an engine-mounted, engine-driven fuel oil pump that takes fuel from the fuel oil day tank. The lubrication system is contained on the engine skid and includes an engine oil sump, a main engine driven oil pump, and a continuous engine prelube system consisting of an ac and dc motor-driven prelube pump and electric heater. The prelube system maintains the engine lubrication system in service when the diesel engine is in standby mode.

Each diesel generator is a direct-shaft-driven, air-cooled self-ventilated machine. The generator component design is in compliance with the National Electrical Manufacturers Association (NEMA) Standard MG-1, "Motors and Generators." Each generator produces its rated power at 6900 V, 60 Hz. Each generator's continuous rating is based on supplying the non-safety electrical loads which provide shutdown capability using non-safety-related systems. The generators can also provide power for additional investment protection ac loads manually after the loads required for orderly shutdown have been satisfied. The selected unit rating has a design margin to accommodate possible derating resulting from other site conditions. The diesel generator unit is able to reach the rated speed and voltage, and can be ready to accept loads, within 120 seconds after a start signal. The generator exciter and voltage regulator systems are capable of providing full voltage control during operating conditions including postulated fault conditions. Each generator has an automatic load sequencer to enable controlled loading on the generator. The automatic load sequencer connects selected loads at predetermined intervals. This feature allows recuperation of generator voltage and frequency to rated values prior to the connection of the next load.

To enable periodic diesel generator testing, each generator is synchronized to a local panel, as well as to the MCR. Each standby diesel generator is tested to verify its capability to provide 4000 kW while maintaining the output voltage and frequency within the design tolerances of 6900±10 percent Vac and 60±5 percent Hz. The test duration will be the time required to reach engine temperature equilibrium plus 2.5 hours. This duration is sufficient to demonstrate long-term capability.

Preoperational tests are conducted to verify proper operation of the ac power system. The preoperational tests include operational testing of the diesel load sequencer and diesel generator capacity testing. The diesel generators are not safety-related and will be maintained in accordance with the requirements of the overall plant maintenance program. This program will cover the preventive, corrective, and predictive maintenance activities of the plant systems and equipment and will be presented in the COL application. This COL information is discussed in DCD Tier 2, Section 8.3.3, "Combined License Information for Onsite Electrical Power." This is COL Action Item 8.3.1.2-1.

The applicant has provided sufficient information to demonstrate that the standby diesel generator is capable of providing a backup source of electrical power to onsite equipment needed to support decay heat removal operation during reduced reactor coolant system inventory and midloop operation.

8.3.1.3 Ancillary ac Diesel Generators

The applicant has included two ancillary diesel generators located in the annex building to provide power to meet the post-72 hour power requirements following an extended loss of offsite power sources. Each ancillary diesel generator output is connected to a distribution panel. The outgoing feeder circuits from the distribution panel are connected to cables which are routed to the Divisions B and C voltage regulating transformers and to the passive containment cooling system (PCS) pumps. Class 1E voltage regulating transformers power the post-accident monitoring loads, the lighting in the MCR, and ventilation in the MCR and Divisions B and C instrumentation and control (I&C) rooms. It also provides power to support operation of the ancillary generator's lighting and fuel tank heating equipment. The ancillary diesel generators are not needed for refilling the PCS water storage tank, post-accident monitoring, or lighting for the first 72 hours following a loss of all other ac sources. They also are not needed for spent fuel makeup for the first 7 days following the loss of all other ac sources.

The generators are commercial-grade, skid-mounted packaged units, and are seismically designed. Generator control is manual from a control integral with the diesel skid package. The fuel for ancillary generators is stored in a tank located in the same room as the generators. This tank is analyzed to show that it will withstand a safe-shutdown earthquake (SSE) and holds sufficient fuel for 4 days of operation. Each ancillary diesel generator is tested to verify the capability to provide 35 kW, while maintaining the output voltage and frequency within the design tolerances of 480±10 percent Vac and 60±5 percent Hz. The 35 kW capacity is sufficient to meet the post-72 hours nominal load requirement.

Based on the ancillary ac diesel generator capabilities described above, the staff concludes that the ancillary ac diesel generators are acceptable as backup power sources for the longer term (post-72 hours) following a loss of all other ac power sources. Therefore, the staff finds the ancillary ac diesel generators to be acceptable.

8.3.1.4 Heat Tracing System

The electric heat tracing system is non-safety-related and provides electrical heating where a temperature above ambient is required for system operation and freeze protection. It is a part of the permanent non-safety-related loads and is powered from the diesel backed 480 Vac MCC through 480 V-208Y/120 V transformers and distribution panels. The staff finds the heat tracing system to be acceptable.

8.3.1.5 Containment Building Electric Penetrations

Individual electrical penetrations are provided for each electrical service level. Electrical circuits passing through electrical penetrations have primary and backup protective devices. These devices coordinate with the thermal capability curves (I^2t) of the penetration assemblies. The penetrations are rated to withstand the maximum short circuit currents available without exceeding their thermal limits, for at least longer than the field cables of the circuits. This ensures that the fault or overload currents are interrupted by the protective devices prior to a potential penetration failure. Penetrations are protected for the full range of currents up to the maximum short circuit current available. Primary and backup protective devices protecting Class 1E circuits are Class 1E in accordance with Institute of Electrical and Electronics Engineers (IEEE) Standard 741-1997, "Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations." Primary and backup protective devices protecting non-Class 1E circuits are non-Class 1E. The staff notes that IEEE 741-1997 is not endorsed by a regulatory guide.

The electrical circuits passing through electrical penetrations are protected by coordinated primary and backup protective devices. The primary and backup protective devices protecting Class 1E circuits are in accordance with IEEE 317-1976, "Electric Protection Assemblies in Containment Structures for Nuclear Power Generating Stations," which is endorsed by RG 1.63, "Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants," Revision 3. The design is, therefore, acceptable.

8.3.1.6 Grounding System

The AP1000 grounding system will comply with the guidelines provided in IEEE 665-1995, "Guide for Generating Station Grounding," and IEEE 1050-1996, "Guide for Instrumentation and Control Equipment Grounding in Generating Stations." Specifically, the grounding system consists of the following four subsystems:

(1) station grounding grid
(2) system grounding
(3) equipment grounding
(4) instrument and computer grounding

The station grounding grid subsystem consists of buried, interconnected bare copper conductors and ground rods forming a plant ground grid matrix. The subsystem will maintain a uniform ground potential and will limit the step-and-touch potentials to safe values under all fault conditions.

The system grounding subsystem will provide grounds of the neutral points of the main generator, main step-up transformers, auxiliary transformers, load center transformers, and onsite standby diesel generators. The main and diesel generator neutrals will be grounded through grounding transformers providing high-impedance grounding. The main step-up and load center transformer neutrals will be grounded solidly. The auxiliary (unit and reserve) transformer secondary winding neutrals will be resistance-grounded.

The equipment grounding subsystem will ground the equipment enclosures, metal structures, metallic tanks, ground bus of switchgear assemblies, load centers, MCCs, and control cabinets with ground connections to the station ground grid.

The instrument and computer grounding subsystem will ground plant instruments and computers through a separate radial grounding system consisting of isolated instrumentation ground buses and insulated cables. The radial grounding systems will be connected to the station grounding grid at only one point, and will be insulated from all other grounding circuits.

The final design of the grounding and the lightning protection system depends on the soil resistivity and lightning activity in the area. DCD Tier 2, Section 8.3.3 states that the COL applicant referencing the AP1000 certified design will address the design grounding and lightning protection. This is COL Action Item 8.3.1.6-1.

8.3.1.7 Lightning Protection

In accordance with the Lighting Protection Code, National Fire Protection Association (NFPA) 780-1997, "Standard for the Installation of Lightning Protection Systems," the lightning protection system, consisting of air terminals and ground conductors, will protect the containment/shield building, cooling towers, switchyard, and other exposed structures and buildings housing safety-related and fire protection equipment. In addition, lightning arresters will be provided in each phase of the transmission lines and at the high voltage terminals of the outdoor transformers. The isophase bus connecting the main generator, main transformer, and medium voltage switchgear will also be provided with lightning arresters. In addition, a surge suppressor will be provided to protect the plant instrumentation and monitoring system from lightning-induced surges in the signal and power cables connected to a device located outside.

Direct strike lightning protection for facilities is accomplished by providing a low-impedance path by which the lightning strike discharge can enter the earth directly. The direct strike lightning protection system (consisting of air terminals, interconnecting cables, down conductors to ground, and other components) will be provided external to the facility in accordance with the guidelines included in NFPA 780-1997. The system will be connected directly to the station ground to facilitate dissipation of the large current of a direct lightning strike. The lightning arresters and the surge suppressor connected directly to the ground provide a low-impedance path to ground for the surges caused or induced by lightning. Thus, damage to facilities and equipment resulting from a lightning strike is avoided.

The final design of direct lightning protection and the associated grounding depends on the lightning activity at the plant site and the soil resistivity of the ground. As discussed in Section 8.3.1.6 of this report, the COL applicant referencing the AP1000 certified design will address the design of its lightning protection system.

8.3.1.8 Raceway and Cable Installation

There are two non-safety-related load groups associated with different transformers, buses, and onsite standby diesel generators. No physical separation is required because these two ac load groups are non-Class 1E and non-safety-related. The power cable ampacities are in accordance with the Insulated Cable Engineers Association (ICEA) publications and the National Electric Code. The derating is based on the type of installation, the conductor and ambient temperature, the number of cables in a raceway, and the groupings of the raceways. A further derating of the cables is applied for those cables that pass through a fire barrier. The method of calculating these derating factors is determined from the ICEA publications and other applicable standards.

For circuits that are routed through conduit and partly through trays or underground ducts, the cable size is based on the ampacity in that portion of the circuit with the lowest indicated current carrying capacity.

In DCD Tier 2, Section 8.3.1.3.3, "Cable Derating and Cable Tray Fill," the cable tray design is based on random cable fill of 40 percent of usable tray depth. The applicant has committed to analyze the tray fill if it exceeds the above stated maximum fill.

Separate raceways are provided for medium voltage power, low voltage power, and control, as well as instrumentation cables. Non-Class 1E raceways and supports, installed in seismic Category I structures, are designed and/or physically arranged so that an SSE could not cause unacceptable structure interaction or failure of seismic Category I components.

The raceway system for non-Class 1E ac circuits complies with IEEE 422-1986, "IEEE Guide for the Design and Installation of Cable Systems in Power Generating Stations," with respect to installation and support of cable runs between electrical equipment, including physical protection. The staff notes that IEEE 422-1986 is not endorsed by a regulatory guide.

On the basis of the staff's review of the information provided, the staff considers that the raceway and cable installation description is adequate, and therefore, acceptable.

8.3.1.9 Conclusions

The applicant has specified appropriate design criteria for the non-Class 1E onsite ac power system. Because the passive safety systems do not require Class 1E ac onsite power, the staff concludes that the onsite power systems (except for the Class 1E batteries discussed below in Section 8.3.2 of this report) are acceptable.

8.3.2 Direct Current Power and Uninterruptible Power Systems

Regulatory Evaluation

The dc power systems include those dc power sources (and their distribution systems and auxiliary supporting systems) provided to supply motive or control power to safety-related equipment. The staff's review covers the information, analyses, and referenced documents for the dc onsite power system. Acceptance criteria are based on GDC 17, as they relate to the capability of the onsite electrical power system to facilitate the functioning of structures, systems, and components (SCCs) important to safety. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2, "D-C Power Systems (Onsite)."

Technical Evaluation

The dc power system consists of Class 1E and non-Class 1E dc power systems. Each system consists of ungrounded batteries, dc distribution equipment, and a UPS.

The Class 1E dc and UPS system supplies power for Class 1E equipment required for the plant instrumentation, control, monitoring, and other vital functions needed for plant safety. In addition, the Class 1E dc and UPS system powers the lighting in the MCR and in the remote shutdown area.

The Class 1E dc and UPS system also supplies power for the safe shutdown of the plant without the support of battery chargers, during a loss of all ac power sources coincident with a design-basis accident (DBA). The system is designed so that no single failure will result in a condition that will prevent the safe shutdown of the plant.

The non-Class 1E dc and UPS system provides power to the plant's non-Class 1E control and instrumentation equipment and loads that are required for plant operation and investment protection, and to the hydrogen igniters located inside containment. Operation of the non-Class 1E dc and UPS systems is not required for plant safety.

8.3.2.1 Class 1E dc and UPS System

The AP1000 Class 1E dc and UPS system consists of Class 1E dc distribution, the Class 1E uninterruptible power system, and testing and inspection of the dc power system. The Class 1E dc and UPS system design was reviewed against GDC 2, "Design Bases for Protection Against Natural Phenomena," GDC 4, "Environmental and Missile Design Basis," GDC 17, GDC 18, and GDC 50, "Containment Design Basis," as listed in the SRP. GDC 5, "Sharing of Structures, Systems, and Components," is not applicable to the AP1000 design because this design is only for a single unit.

8.3.2.1.1 Class 1E dc Distribution

The Class 1E dc power system consists of four independent 125 V Class 1E dc safety system divisions (Divisions A, B, C, and D). Divisions A and D are each comprised of one battery bank, one switchboard, and one battery charger. Divisions B and C are each comprised of two battery banks, two switchboards, and two battery chargers.

A battery bank in each of the four divisions, designated as a 24-hour battery bank, is used to provide power to the loads required for the first 24 hours following a loss of all ac power sources concurrent with a DBA. The second battery bank in Divisions B and C, designated as a 72-hour battery bank, is used for loads requiring power for 72 hours following the same event. In the event of a LOOP coincident with a generator trip, ac power to the battery charger is provided from two separate non-Class 1E onsite standby diesel generators. Divisions A and C chargers receive ac power from one diesel generator, and Divisions B and D chargers from the second diesel generator. Provisions are also made to power Divisions B and C chargers from transportable ac generators during the post-72-hour period. No load shedding or load management program is needed to maintain power during the required 24-hour safety actuation periods.

In request for information (RAI) 435.015, the staff expressed a concern regarding the ability of the dc system to suppress voltage spikes that may result from surges caused by deenergized, highly inductive loads, since the battery charger is powered from the ac system. By letter dated October 2, 2002, the applicant responded that the dc system is protected from surges generated on the ac system by the isolation provided by the battery chargers and voltage regulating transformers. To further assure protection, metal oxide varistor surge suppressors are used at the input terminals to all battery chargers and inverters to minimize the potential for component damage resulting from electrical transients. The metal oxide varistor surge suppressor is safe to use. It does not emit toxic fumes upon failure and arcing or burning. On the dc system, inductive loads are limited to relay and motor starter coils. Surge suppression devices are installed across the coils to limit voltage spikes when the coils deenergize. In the ac system surge arresters are used in locations where switching or lightning transients may occur. In addition, surge suppressors are provided to protect the plant instrumentation and monitoring system from lightning-induced surges in the signal and power cables connected to devices located outside.

The Class 1E dc system is ungrounded. Thus, a single ground fault does not cause immediate loss of the faulted system. However, Class 1E detection with alarms is provided for each power division, so that ground faults can be located and removed before a second fault could disable the affected circuit.

Each Class 1E 24-hour and 72-hour battery charger is tested to verify its capability to provide power while maintaining the output voltage within the specified range. Each battery charger has an input ac and output dc circuit breaker for the purpose of power source isolation. Each battery charger prevents the ac supply from becoming a load on the battery due to power feedback (as a result of the loss of ac power to the chargers). Each battery charger has a built-in current limiting circuit, adjustable between 110 to 125 percent of its rating, to hold down the output current in the event of a short circuit or overload on the dc side. The output of the charger is ungrounded and filtered. The output float and equalizing voltages are adjustable.

The battery chargers have an equalizing timer and a manual bypass switch to permit periodic equalizing charges. Each charger is capable of providing continuous Class 1E loads while providing sufficient power to charge a fully discharged battery within a 24-hour period.

The AP1000 Class 1E 125 Vdc batteries are sized to meet the design requirements of their connected load, without the charger support, for the corresponding time periods of 24 and 72 hours. The batteries have been sized in accordance with IEEE 485-1997. The staff notes that IEEE 485-1997 is not endorsed by a regulatory guide. The staff considers that the governing factor for the AP1000 Class 1E battery size is the steady-state loading condition. The steady-state loads are required to operate for a long period of time (0 to 24 hours and 0 to 72 hours). Therefore, the staff considers the battery sizing acceptable.

Monitoring and Alarms

Each battery bank, including the spare, has a battery monitor system which detects battery open circuit conditions and monitors battery voltage. The battery monitor provides a trouble alarm locally and in the MCR. The battery monitors are not required to support any function.

The specific considerations regarding the monitoring of the dc power systems are derived from Section 7.4 of IEEE 946-1992, "IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations." Although IEEE 946-1992 is not endorsed by a regulatory guide, the staff considers monitoring to be beneficial. In summary, these general considerations state that the dc systems (batteries, distribution system, and chargers) should be monitored to the extent that they can be shown to be ready to perform their intended functions. The recommended instruments, controls, alarms, and their locations are described below:

Instrument/Alarm/Control	Main Control Room	Local
Battery Current (Ammeter Charge/Discharge)		X
Battery Charger Output Current (Ammeter)		X
DC Bus Voltage (Voltmeter)		X
Battery Charger Output Voltage (Voltmeter)	X	

Instrument/Alarm/Control	Main Control Room	Local
Ground Detector (Voltmeter)	X	
DC Bus Undervoltage Alarm	X	
DC System Ground Alarm	X	
Battery Breaker/Switch Open Alarm	X	
Battery Charger Output Breaker Open Alarm	X	
Battery Charger DC Output Failure Alarm	X	
Battery Charger AC Power Failure Alarm	X	
Charger Low DC Voltage Alarm	X	
Charger High DC Voltage Shutdown Relay (opens main ac supply breaker to the charger)	X	
Battery Test Breaker Closed Alarm	X	X

Monitoring and alarming of dc current and voltages is through the plant control system, which includes a battery discharge rate alarm. The operating range for the safety-related dc power system is 105 to 140 Vdc. This voltage range envelopes the DBA conditions; the batteries have been sized to provide adequate voltage at the end of the battery duty cycle.

In RAI 435.006, the staff questioned whether the standard, molded-case ac breakers will be used in dc circuits because the dc interrupting rating will generally be less than the ac value. Many manufacturers do not publish dc application data for these breakers. By letter dated October 2, 2002, the applicant responded that the limited availability of molded-case breakers with a high dc interrupting rating is known in the industry. However, there are manufacturers who can supply molded case breakers with UL-listed interrupting ratings for dc circuits. The application of molded-case circuit breakers in the AP1000 dc distribution system is described below:

- The AP1000 design generally utilizes fusible disconnect switches in the Class 1E dc system. If a molded-case circuit breaker is used in a particular circuit, it will be sized to meet the dc interrupting rating specification. Proper documentation will be obtained to ensure that the molded-case breakers have adequate dc interrupting rating.

- The non-Class 1E dc power system has molded-case circuit breakers. These breakers will have UL-listed current interrupting ratings for dc applications.

The Class 1E dc switchboards employ fusible disconnect switches and have adequate short circuit and continuous current ratings. Fused transfer switch boxes, equipped with double pole, double throw transfer switches, are provided to facilitate battery testing and maintenance. The fuses are housed in the fused transfer switch boxes. To provide maximum protection coverage from short circuit, each fused transfer switch box is located as close to the battery terminals as possible. The fuses are sized in accordance with the criteria stated in Section 7.1 of IEEE 946-1992. The continuous current rating of the fuses is sufficiently high to prevent damage to the fuse element at the 1-minute current rating of the battery, and sufficiently low to ensure interruption of the short circuit current available from the battery at end-of-discharge voltage.

8.3.2.1.2 Class 1E Uninterruptible Power System

The Class 1E UPS provides power at 208/120 Vac to four independent divisions of Class 1E instrument and control power buses. Divisions A and D each consists of one Class 1E inverter with an instrument and control distribution panel and a Class 1E backup regulating transformer. The inverter is powered from the respective 24-hour battery bank. Divisions B and C each consist of two inverters, two instrument and control distribution panels, and a backup regulating transformer. One inverter is powered by the 24-hour battery bank and the other by the 72-hour battery bank. Under normal operation, the Class 1E inverters receive power from the associated battery bank. If an inverter is inoperable, or the Class 1E 125 Vdc input to the inverter is unavailable, the power is transferred automatically to the backup ac source by a static transfer switch, featuring a make-before-break contact arrangement. The backup power is received from the diesel generator backed non-Class 1E 480 Vac bus through the Class 1E regulating transformer. In addition, a manual mechanical bypass switch is provided to allow connection of a backup power source when the inverter is removed from service for maintenance.

The Class 1E dc and UPS system is designed to accommodate component failures, such as the loss of a battery charger, a battery, or an inverter, without the loss of power to either the dc bus or the ac instrumentation and control power bus. In RAI 435.008, the staff expressed a concern that failures of the UPS system constitute one of the main causes of forced plant outages and requested the applicant to discuss the design aspects that will ensure that the failure or unavailability of a single battery, battery charger, or inverter will not result in a plant trip. By letter dated October 2, 2002, the applicant responded that a failure or the unavailability of a single safety-related battery, battery charger, or inverter will not result in a plant trip or a forced outage. DCD Tier 2, Section 8.3.2, "DC Power Systems," provides a description of the dc power systems. The dc power systems include a spare Class 1E battery bank with a spare battery, battery charger, and permanently installed cable connections that allow the spare bank to be connected to the affected bus by a plug-in, twist-lock disconnect. The spare bank can be aligned to either the Class 1E or the non-Class 1E dc power system, if component failures occur.

Following a loss of either a Class 1E or a non-Class 1E battery charger, which is normally providing power to the associated dc bus, the battery would immediately supply the affected bus, maintaining continuity of power to it. Following a loss of either a Class 1E or a non-Class 1E battery, the battery charger would continue to supply power to the dc bus. With the loss of either a battery charger or a battery, continuity of power to the associated dc bus is maintained. Therefore, there is no affect on plant operation since the spare battery can be aligned while the faulty component is repaired. Following the loss of either a Class 1E or a non-Class 1E inverter, the associated dc bus remains energized and the dc loads are not affected. The 208Y/120 Vac I&C power bus associated with the failed inverter remains continuously energized.

Each UPS includes an inverter and a Class 1E backup voltage regulating transformer that can supply the associated I&C bus, if the inverter fails. The UPS includes a static transfer switch that automatically transfers the bus to the regulated power source if power is unavailable from the inverter. A manual mechanical bypass switch is also included in the UPS to provide a second connection for the bus to the backup regulated power source when the inverter is removed from service for maintenance. Therefore, with a failure of a single battery charger or a single battery, power is continuously maintained to the dc buses. With a failure of an inverter, power to the I&C power bus is automatically transferred to a Class 1E regulated backup power source. With a single failure or the unavailability of these components, the associated buses remain energized, thereby preventing a plant trip or forced outage. This meets the single failure criterion. Therefore, the staff finds this acceptable.

In a RAI 435.010, the staff requested information from the applicant regarding the possibility of age-related failures of inverters and chargers, especially with an increase in ambient temperatures being considered as the main cause of age-related failures (particularly for capacitors, transformers, and semiconductors). The applicant was asked to describe the conservatism included in the AP1000 design with respect to temperature margins, and whether any forced air cooling for the battery chargers is required. By letter dated October 2, 2002, the applicant responded that the Class 1E and non-Class 1E inverters and battery chargers (UPS equipment) are located in a controlled environment. The room ambient temperature is maintained between 19 °C (66.2 °F) and 23 °C (73.4 °F) for the Class 1E equipment and between 10 °C (50 °F) and 40 °C (104 °F) for the non-Class 1E UPS equipment. The UPS equipment is rated for continuous operation at an ambient temperature of 40 °C (104 °F). In addition, the temperature-sensitive components such as capacitors, transformers, and semiconductors, used in the UPS equipment are designed to continuously withstand higher temperatures of about 60 °C (140 °F) to 70 °C (158 °F). In addition, Class 1E electrical components are environmentally qualified. Therefore, considering the conservative temperature margins provided in the AP1000 design, an age-related failure of the UPS equipment is not expected.

Air cooling is provided by the nuclear island nonradioactive ventilation system for Class 1E UPS equipment located in the auxiliary building. This system is described in DCD Tier 2, Section 9.4.1, "Nuclear Island Nonradioactive Ventilation System." The non-Class 1E UPS equipment is located in the annex building. Air cooling is provided in the annex building by the annex building nonradioactive ventilation system which is described in DCD Tier 2, Section 9.4.2, "Annex/Auxiliary Buildings Nonradioactive HVAC System." Therefore, based on the conservative temperature margins provided in the AP1000 design, an age-related failure of the UPS equipment is not expected. The staff finds the conservatism in the design to be acceptable.

In a RAI 435.014, the staff requested clarification as to whether the AP1000 design acceptably addresses total harmonic distortion (THD) for nonlinear loads. The loads used for digital control power supplies and computers in the AP1000 are inherently nonlinear in nature. Also, variable speed drive systems and fluorescent lighting ballasts introduce harmonics into the plant distribution system. By letter dated October 2, 2002, the applicant responded that THD due to nonlinear loads has been addressed in the AP1000 design. The UPS inverters have harmonic filters designed specifically to reduce the effects of large third, fifth, seventh, and higher-order harmonics that may result from anticipated 100 percent nonlinear loads. To provide high-quality power from the UPS system, the inverters are specified to power loads with a crest factor of 2 or higher (ratio of peak to root mean square [rms] value). The variable speed drives used for the RCPs have special filters to eliminate the introduction of harmonics into the distribution system. Also, the battery chargers are furnished with output filtering to limit ripple currents feeding into the dc power supply for the inverters. The applicant has shown that the issues associated with THD have been adequately addressed. Therefore, the staff considers this to be resolved.

The applicant performed a FMEA for the Class 1E dc and UPS system. In the event of a LOOP coincident with a generator trip, ac power to the battery charger is provided from two separate non-Class 1E onsite standby diesel generators. The Class 1E battery chargers and Class 1E regulating transformers are designed to limit the input ac current to an acceptable value under faulted conditions on the output side. Circuit breakers exist at the input and output sides for protection and isolation. The circuit breakers are coordinated and periodically tested to verify their current-limiting characteristics.

The four divisions are completely independent and located in separate rooms, have no shared equipment, and cannot be interconnected. Their circuits are routed in dedicated, physically separated raceways. This electrical and physical separation prevents the failure or unavailability of a single battery, battery charger, or inverter from adversely affecting a redundant division. The battery monitoring system detects battery open circuit conditions and monitors battery voltage. The Class 1E dc system is ungrounded. Thus, a single ground fault does not cause immediate loss of faulted system. A spare battery bank and charger enables testing, maintenance, and equalization of battery banks offline. This configuration provides the capability for each battery bank or battery charger to be separately tested and maintained (including battery discharge tests, battery cell replacement, battery charger replacement) during plant operation.

The AP1000 design uses battery monitors. These monitors continuously monitor the condition of the battery by measuring intercell resistance to provide advance indication of a maintenance requirement. Also, the batteries are in a controlled environment during normal operation. The controlled environment helps eliminate the possibility of a common mode failure caused by a high room ambient temperature.

8.3.2.1.3 Testing and Inspection of the dc Power System

GDC 18 requires that electric power systems important to safety shall be designed with the following capabilities:

- the ability to permit appropriate periodic inspection and testing of important areas and features (such as wiring, insulation, connections, and switchboards) in order to assess the continuity of the systems and the condition of their components
- the ability of periodically test the operability and functional performance of the components of the systems

- the ability to periodically test the operability of the systems as a whole (under conditions as close to design as practical) and the full operation sequence that brings the systems into operation

The applicant stated that components of the 125 Vdc system undergo periodic tests to determine the condition of the system. Batteries are checked for electrolyte level, specific gravity, and cell voltage. The surveillance testing of the Class 1E 125 Vdc system is performed as required by the AP1000 DCD Tier 2, Chapter 16, "Technical Specifications." The staff concludes that the Class 1E 125 Vdc electric power system is periodically tested and inspected in accordance with GDC 18 and is, therefore, acceptable.

8.3.2.1.4 Conclusions

The applicant has met the requirements of GDC 2 with respect to the ability of the SSCs of the Class 1E dc and UPS system to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods. The Class 1E dc and UPS system and components are located in seismic Category I structures which provide protection from the effects of tornadoes, tornado missiles, and floods. In addition, the Class 1E dc and UPS system and components have a quality assurance designation as "Class 1E."

The applicant has met the requirements of GDC 4 with respect to the ability of the SSCs of the Class 1E dc and UPS system to withstand the effects of missiles and environmental conditions associated with normal operation and postulated accidents based on adequate plant design and equipment qualification program.

GDC 5 is not applicable to the AP1000 design because this design is only for a single unit.

The applicant has met the requirements of GDC 17 with respect to the Class 1E dc and UPS system's (1) capacity and capability to permit functioning of SSCs important to safety, (2) the independence and redundancy to perform its safety function assuming a single failure, and (3) provisions to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit or the loss of power from the transmission network.

The applicant has met the requirements of GDC 18 with respect to the Class 1E dc and UPS system being designed to be testable during operation as well as during shutdown.

The applicant has met the requirements of GDC 50 with respect to penetrations containing circuits of the Class 1E dc and UPS system. Containment electrical penetrations have been designed to accommodate, without exceeding their design leakage rate, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident (LOCA) concurrent with the maximum short circuit current versus time condition that could occur given, single random failures of circuit overload protective devices.

Therefore, the staff concludes that the plant design is acceptable.

8.3.2.2 Physical Independence of Redundant Circuits

There are four safety-related separation groups for the cable and raceway system (Groups A, B, C, and D). Separation Group A contains safety-related circuits from Division A. Similarly, separation Groups B, C, and D contain safety-related circuits from Divisions B, C, and D, respectively. There is also a Group N which contains non-safety-related circuits. Cables of each separation group are run in separate raceways and are physically separated from cables of other separation groups.

Group N raceways are separated from safety-related Groups A, B, C, and D. Raceways from Group N are routed in the same areas as the safety-related groups according to spatial separation as described in RG 1.75, "Physical Independence of Electric Systems," which endorses IEEE 384-1974, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits." The applicant has applied IEEE 384-1974 with the following exceptions:

- Within the MCR and remote shutdown area (non-hazard areas), the minimum vertical separation for an open cable tray is 7.6 centimeters (cm) (3 in.) and the minimum horizontal separation is 2.54 cm (1 in.).

- Within general plant areas (limited hazard areas), the minimum vertical separation is 0.3 m (12 in.), and the minimum horizontal separation is 0.15 meter (m) (6 in.) for the open cable trays with low voltage power circuits for cable sizes <2/0 American Wire Gauge. For configurations that involve exclusively limited energy content cables (I&C), these minimum distances are reduced to 7.65 cm (3 in.) and 2.54 cm (1 in.), respectively.

- Within panels and control switchboards, the minimum horizontal separation between components or cables of different separation groups (both field-routed and vendor-supplied internal wiring) is 2.54 cm (1 in.), and the vertical separation distance is 0.15 m (6 in.).

- For configurations involving an enclosed raceway and an open raceway, the minimum vertical separation is 2.54 cm (1 in.), if the enclosed raceway is below the open raceway.

Section 5.1.1.2 of IEEE 384-1974 states that the minimum separation distance can be established by analysis of the proposed cable installation. This analysis shall be based on the tests performed to determine the flame retardant characteristics of the proposed cable installation, considering features such as cable insulation and jacket materials, cable tray fill, and cable tray arrangement. The applicant has established the minimum separation distances by performing an analysis of the proposed cable installation. This analysis is based on 10 tests performed and the findings published in the IEEE Transactions on Energy Conversion, Volume 5, No. 3, September 1990, titled, "Cable Separation—What Do Industry Testing Programs Show?" These findings were also published by the IEEE Working Group on Independence Criteria, SC-6.5, of the Nuclear Power Engineering Committee. The staff reviewed the results of the 10 tests and found them acceptable. Therefore, the staff finds the lesser distances used by the applicant in its design to be acceptable.

Non-Class 1E circuits are electrically isolated from Class 1E circuits by isolation devices and are physically separated from Class 1E circuits in accordance with the above separation criteria. Class 1E circuits from different separation groups are electrically isolated by isolation devices, shielding, and physical separation, in accordance with RG 1.75 for circuits in raceways. Non-Class 1E raceways and supports installed in seismic Category I structures are designed and/or physically arranged so that an SSE could not cause failure of seismic Category I components.

Power and control cables are installed in conduits or ventilated bottom trays (ladder type). Solid tray covers are used in outdoor locations. Instrumentation cables are routed in conduits or solid bottom cable trays with solid tray covers. Separate trays are provided for each voltage level—6.9 kV, low voltage power (480 Vac, 120 Vac, 125 Vdc), high-level signal and control (120 Vac, 125 Vdc), and low-level signal (instrumentation). Cable trays are physically arranged from top to bottom, in accordance with the function and voltage class of the cables, and with the highest voltage at the top. Vertically stacked trays are arranged from top to bottom with a minimum of 12 inches (0.3 m) vertical spacing maintained between trays of different service levels within the stack.

Raceways installed in seismic Category I structures have seismically designed supports, or are shown not to affect safety-related equipment should they fail. Conduits are attached to seismic Category I equipment with flexible type connections.

Where hazards to safety-related raceways are identified, a minimum separation is maintained between the break and/or missile source and any safety-related raceway. Alternatively, a barrier designed to withstand the effects of the hazard is placed to prevent damage to the raceways of redundant systems. Spacial separation is provided where redundant circuits, devices, or equipment (different separation groups) are exposed to the same external hazards. Otherwise, qualified barriers are installed.

The staff finds that the physical independence of the redundant circuits meets RG 1.75 with the exceptions discussed above. The distances specified in the exceptions to RG 1.75 are acceptable based on the staff's review of the 10 tests. Therefore, the physical independence of the redundant circuits is acceptable.

8.3.2.3 Non-Class 1E dc and UPS System

The non-Class 1E dc and UPS system consists of the dc electric power supply and distribution equipment that provide dc and uninterruptible ac power to the plant non-Class 1E dc and ac loads (that are needed for plant operation and investment protection) and to the hydrogen igniters located inside containment. The non-Class 1E dc and UPS system consists of two subsystems representing two separate power trains. The subsystems are located in separate rooms. Each subsystem consists of separate dc distribution buses, but these can be connected by a normally open circuit breaker. Each dc subsystem includes battery chargers, batteries, dc distribution equipment, and associated monitoring and protective devices.

Direct current buses 1, 2, and 3 provide 125 Vdc power to the associated inverter units that supply the ac power to the non-Class 1E UPS system. An alternative regulated ac power source for the UPS buses is supplied from the associated regulating transformers. Bus 4 supplies large dc motors and other dc power loads, but not inverter loads.

A 480 Vac distribution system backed by the onsite standby diesel generator provides the normal ac power to the battery chargers. The batteries supply the dc power in case the battery chargers fail to supply the dc distribution bus system loads. The batteries are sized to supply the system loads for a period of at least 2 hours after loss of all ac power sources. Each non-Class 1E dc distribution subsystem bus has provisions to allow connection of a spare non-Class 1E battery charger, in case its non-Class 1E battery charger is unavailable because of maintenance, testing, or failure. There are also provisions for the non-Class 1E dc system to use the Class 1E spare battery bank as a temporary replacement for any non-Class 1E battery bank. In this configuration, the spare Class 1E battery bank does not simultaneously supply Class 1E safety loads. Additionally, the design includes two current interrupting devices to preserve the spare Class 1E battery integrity should the non-Class 1E bus experience an electrical fault. Therefore, the Class 1E spare battery would not be degraded.

The non-Class 1E 125 Vdc system provides dc and UPS to the plant's non-Class 1E dc and ac loads that are needed for plant operation and investment protection. The provision of two separate current interrupting devices helps to ensure the independence of the Class 1E dc system from faults or failures in the non-Class 1E systems, and is therefore acceptable.

8.4 Other Electrical Features and Requirements for Safety

The staff reviewed certain safety-related electrical features of the AP1000 design to determine whether they are implemented in accordance with the applicable criteria set forth in Section 8.1 of this report.

8.4.1 Containment Electrical Penetrations

The applicant stated that the penetrations conform to the same functional service level as the cables (e.g., low-level instrumentation is separated from power and control penetrations). Individual electrical penetrations are provided for each electrical service level, and are arranged physically from top to bottom in accordance with the function and voltage class of the cables. For modular type penetrations (three penetration modules in one nozzle), the applicant has assigned the following:

- one module for low voltage power
- one module for 120 Vac/125 Vdc control and signal
- one module for instrumentation signal

Penetrations carrying medium voltage power cables have thermocouples to monitor the temperature within the assembly at the spot expected to have the hottest temperature. Electrical circuits passing through electrical penetrations have primary and backup protective devices. These devices are to be selected to coordinate with the thermal capability (I^2t) of the penetration assemblies. The applicant stated that the penetrations can withstand the maximum short circuit currents available either continuously, without exceeding their thermal limit, or at least longer than the field cables of the circuits. Therefore, the faults or overload currents are interrupted by the protective devices before a potential failure of a penetration. Penetrations are protected for the full range of current up to the maximum short circuit current available.

The containment electrical penetration assemblies for the AP1000 are designed to withstand, without loss of mechanical integrity, the maximum available fault current for a sufficient period of time to allow backup circuit protection to operate, assuming a failure of the primary protective device. This is in accordance with IEEE 317-1983, "Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," as augmented by the recommendations of RG 1.63, Revision 3. Primary and backup protective devices protecting Class 1E circuits are Class 1E and are coordinated. DCD Tier 2, Section 8.3.3 states that the COL applicants referencing the AP1000 certified design will address the provisions for periodically testing the penetration protection devices. This is COL Action Item 8.4.1-1.

8.4.2 Reactor Coolant Pump Breakers

The RCPs are powered from the four switchgear buses located in the turbine building. One RCP is powered by each bus. Variable speed drives are provided for RCP startup. Each RCP is powered through two Class 1E circuit breakers connected in series. These are the only Class 1E circuit breakers used in the main ac power system for the specific purpose of satisfying the safety-related tripping requirements of these pumps. This ensures that the RCPs are tripped before the passive systems start.

The RCP trip function is a part of the engineered safeguards needed to respond to a design-basis LOCA, and, as a result, are implemented with Class 1E circuit breakers. Therefore, the staff finds the provision of two Class 1E circuit breakers for each RCP to be acceptable since they will allow the operation of the passive systems as designed.

8.4.3 Thermal Overload Protection Bypass

Motor-operated valves, with thermal overload protection devices for the valve motors, are used in safety systems and their auxiliary supporting systems. Operating experience has shown that indiscriminate application of thermal overload protection devices to the motors associated with these valves could result in a needless hindrance to the successful completion of safety-related functions. RG 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves" (November 1975), recommends bypassing thermal overload devices during accident conditions (Regulatory Position C.1), or properly selecting the setpoint for the thermal overloads in a manner that precludes spurious trips (Regulatory Position C.2). Westinghouse Topical Report WCAP-15799, Revision 1, "AP1000 Conformance with SRP Acceptance Criteria," states that the AP1000 design will comply with Regulatory Position C.1 of RG 1.106. The only safety-related electric motor operated valves are dc valves. For non-Class 1E valve motor operators, the thermal overload protection will remain in service at all times. The staff finds this is acceptable.

8.4.4 Power Lockout to Motor-Operated Valves

BTP ICSB 18 (PSB), "Application of the Single-Failure Criterion to Manually-Controlled Electrically-Operated Valves," states that all valves that require power lockout to meet the single failure criterion in the fluid systems, and their required positions, be listed in the technical specifications. It also states that the position indications for these valves should meet the single failure criterion. With respect to the power lockout to the motor-operated valves, this position establishes the acceptability of disconnecting power to electrical components of a fluid system as one means of designing against a single failure that might cause an undesirable component action. DCD Tier 2, Section 7.6, *"Interlock Systems Important to Safety," identified the following* valves which require removal of power consistent with the guidelines of BTP ICSB-18:

- accumulator isolation valves and in-containment refueling water storage tank discharge valve
- passive residual heat removal heat exchanger inlet isolation valve

BTP ICSB-18, Item B-4, states that these valves, which have the electrical power removed to meet the single failure criterion, should have redundant position indication in the MCR, and the position indication system should, itself, meet the single failure criterion. The applicant has provided such indication in the MCR and the remote shutdown panel. Each of the two position sensors is powered from a different non-Class 1E power source. The power lockout to motor-operated valves meets BTP ICSB-18, Item B-4, and is therefore acceptable.

8.4.5 Submerged Class 1E Electrical Equipment as a Result of a Loss-of-Coolant Accident

DCD Tier 2, Section 3.11, "Environment Qualification of Mechanical and Electrical Equipment," discusses the environmental qualification of electrical and mechanical equipment. DCD Tier 2, Table 3.11-1 lists the safety-related electrical and mechanical equipment. The applicant stated that equipment will be qualified for submergence resulting from flooding/wetting. As an alternative to protecting the equipment, the equipment will be evaluated to show that failure of the equipment because of flooding/wetting is acceptable since its safety-related function is not required, or has otherwise been accomplished.

Environmental qualification of electrical equipment is further addressed in Section 3.11 of this report.

8.5 Compliance with Regulatory Issues

8.5.1 Generic Issues and Operational Experience

The staff evaluated the following generic issues and operational experience (bulletins and generic letters). The staff used Topical Report WCAP-15800, Revision 3, "Operational Assessment for AP1000," issued July 2004, and NUREG-0933, "A Prioritization of Generic Safety Issues," to determine the generic issues and operational experience relevant to the AP1000 design.

- A-24, "Qualification of Class 1E Safety-Related Equipment"
- A-25, "Non-Safety Loads on Class 1E Power Sources"
- A-35, "Adequacy of Offsite Power Systems"
- A-44, "Station Blackout"
- B-53, "Load Break Switch"
- B-56, "Diesel Reliability".
- 128: "Electrical Power Reliability"
- II.E.3.1, "Emergency Power Supply for Pressurizer Heaters"
- II.G.1, "Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators"
- BL 80-20, "Failures of Westinghouse Type W-2 Spring Return to Neutral Control Switches"
- GL 80-013, "Qualification of Safety-Related Equipment"
- GL 80-016, "IEB 79-01b Environmental Qualification of Class 1E Equipment"
- GL 80-035, "Effect of a dc Power Supply Failure on ECCS Performances"
- GL 80-082, "IEB 79-01b, Supplement 2, Environmental Qualification of Class 1E Equipment"
- GL 82-09, "Environmental Qualification of Safety-Related Electrical Equipment"
- GL 84-24, "Certificate of Compliance to 10 CFR 50.49, Environmental Qualification of Equipment Important to Safety"

- GL 86-15, "Information Relating to Compliance With 10 CFR 50.49, 'Environmental Qualification of Equipment Important to Safety for Nuclear Power Plants'"
- GL 88-07, "Modified Enforcement Policy Relating to 10 CFR 50.49, 'Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants'"
- GL 88-15, "Electrical Power Systems —Inadequate Control Over Design Process"

The generic issues and operational experience listed above are discussed in Chapter 20 of this report.

8.5.2 Advanced Light-Water Reactor Certification Issues

The following paragraphs discuss the policy, technical, and licensing issues pertaining to passive plant designs that relate to the electrical portion of the AP1000 design.

8.5.2.1 Station Blackout

The requirements of 10 CFR 50.63, "Station Blackout," state that all nuclear power plants must have the capability to withstand a loss of all ac power for an established period of time, and to recover therefrom. The AP1000 design minimizes the potential risk contribution of a station blackout (SBO) by not requiring ac power sources for design-basis events. Safety-related systems do not need non-safety-related ac power sources to perform safety-related functions. The AP1000 safety-related passive systems automatically establish and maintain safe-shutdown conditions for the plant following design-basis events, including an extended loss of ac power sources. The passive systems can maintain these safe-shutdown conditions after design-basis events for 72 hours, without operator action, following a loss of both onsite and offsite ac power sources. DCD Tier 2, Section 1.9.5.4, "Additional Licensing Issue," provides additional information on long-term actions following an extended SBO beyond 72 hours.

The AP1000 design also includes redundant, non-safety-related, onsite ac power sources (diesel generators) to provide electrical power for non-safety-related active systems that provide a defense-in-depth function.

The following AP1000 design features mitigate the consequences of a SBO:

- a full load rejection capability to reduce the probability of loss of onsite power
- safety-related passive residual heat removal heat exchanger
- safety-related passive containment cooling
- bleed and feed capability, using the safety-related automatic depressurization system in conjunction with the water available from the core makeup tanks, accumulators, and in-containment refueling water storage tank

- class 1E batteries sized for 72 hours of operation under SBO conditions
- RCPs without shaft seals
- passive cooling for the rooms containing equipment assumed to operate during SBO conditions (the protection and safety monitoring system cabinet rooms and the MCR) so that this equipment continues to operate for 72 hours

The staff reviewed the applicant's submittal and Section 5, "Loss of All AC Power," of Topical Report WCAP-15985, Revision 2, "AP1000 Implementation of the Regulatory Treatment of Non-Safety-Related Systems Process," dated August 2003 and concludes that no installed non-safety-related systems, structures, and components are relied upon to meet the requirements of 10 CFR 50.63. The staff concludes that the safety-related passive systems are capable of withstanding a loss of all ac power for 72 hours. Therefore, the AP1000 design meets the requirements of 10 CFR 50.63 for 72 hours.

8.5.2.2 Electrical Distribution

The Commission approved the following recommendations in SECY-91-078 for plant designs:

- An alternative offsite power source will be available for non-safety-related loads, unless the design margins for loss of non-safety-related loads are no more severe than turbine-trip-only events in current plants.
- At least one offsite circuit to each redundant safety division will be supplied directly from offsite power sources, with no intervening non-safety-related buses.

The AP1000 design does not have to meet SECY-91-078 because the design does not rely on active systems for safe shutdown.

8.5.2.3 Regulatory Treatment of Non-Safety Systems

In SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs," the NRC set forth policy regarding those systems in passive light-water reactors that are designated non-safety-related, but that may have a significant role in accident and consequence mitigation. The basis for selecting risk-important non-safety systems for the AP1000 is evaluated in WCAP-15985, Revision 2. The non-safety-related active systems in the AP1000 design provide defense-in-depth functions and supplements the capability of the safety-related passive systems. The process of identifying regulatory oversight on non-safety-related systems is referred to as RTNSS.

The ac power from the diesel generators is required to power the normal residual heat removal system (RNS) and to provide a means of supplying power to post-accident monitoring and the input ac power for the Class 1E dc battery chargers. The RNS provides a non-safety-related means to inject water into the reactor coolant system (RCS), following automatic depressurization system actuation in modes 1, 2, 3, and 4. The availability controls require that the ac power supply function be available in modes 1, 2, 3, and 4, when the RNS injection and projection and monitoring system actuation are more risk important.

The ac power is required to power the RNS and its required support systems. The RNS provides a non-safety-related means to normally cool the RCS during shutdown operations. The availability controls require that one offsite and one onsite ac power supply should be available during modes 5 and 6 with reduced inventory, when the loss of RNS cooling is important.. The offsite power source is available through the transmission switchyard and either the main step-up transformer/unit auxiliary transformer or the reserve auxiliary transformer. The onsite power source is available from one of the two diesel generators. If both of these ac power sources are not available, the plant should not enter reduced inventory conditions.

The non-Class 1E dc and UPS systems are important for the diverse actuation system (DAS), based on 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants," and to support engineered safety features actuation (ESFA), based on providing margin in the probabilistic risk assessment sensitivity performed. The availability controls require that the non-Class 1E dc and UPS system be available to the DAS sensors, DAS actuation, and the devices which control the actuated components in mode 1 for DAS ATWS mitigation function, and in modes 1, 2, 3, 4, 5, and 6 for DAS ESFA.

The availability controls require that one ancillary diesel generator, and its fuel oil storage tank, be available during all modes of plant operation. After 72 hours, ancillary diesel generators will power the MCR and I&C room ancillary fans, the PCS recirculation pumps, and MCR lighting.

Therefore, the applicant has provided availability controls for the electrical areas that are RTNSS important and has included these controls into the DCD and in the design certification rule to make the commitment binding on the COL applicant. Unlike the current generation of light-water reactors, the AP1000 uses passive safety systems that rely exclusively on natural forces such as gravity and stored energy to provide water for core and containment cooling. These passive systems do not include active equipment, such as pumps.

For the AP1000 design, the active systems are designated as non-safety-related systems. The non-safety-related systems in the AP1000 design provide defense-in-depth functions and supplement the capability of the safety-related passive systems. Thus, the staff and the industry have defined a process to evaluate the importance of the non-safety-related systems, and for maintaining regulatory oversight of these active systems in the AP1000 design.

The staff reviewed the RTNSS process and finds it acceptable. For an additional discussion on RTNSS refer to Chapter 22 of this report.

9. AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

The following sections describe the U.S. Nuclear Regulatory Commission (NRC) staff's review of the AP1000 fuel storage and handling systems:

- 9.1.1, "New Fuel Storage"
- 9.1.2, "Spent Fuel Storage"
- 9.1.3, "Spent Fuel Pool Cooling and Pool Purification"
- 9.1.4, "Light-Load Handling System (Related to Refueling)"
- 9.1.5, "Overhead Heavy-Load Handling Systems"

9.1.1 New Fuel Storage

The staff has reviewed the AP1000 advanced reactor's new fuel storage capability in accordance with Section 9.1.1, "New Fuel Storage," of NUREG-0800, "Standard Review Plan" (SRP). The staff's acceptance of the new fuel storage facility is contingent on compliance with the following requirements:

- General Design Criterion (GDC) 2, "Design Bases for Protection Against Natural Phenomena," as it relates to the ability of the facility and the structures housing it to withstand the effects of natural phenomena, such as earthquakes

- GDC 5, "Sharing of Structures, Systems, and Components," as it relates to whether shared structures, systems, and components (SSCs) important to safety are capable of performing required safety functions

- GDC 61, "Fuel Storage and Handling and Radioactivity Control," as it relates to the facility design for fuel storage

- GDC 62, "Prevention of Criticality in Fuel Storage and Handling," as it relates to the prevention of criticality

In accordance with SRP Section 9.1.1, compliance with GDC 2 depends on adherence to the guidance of Regulatory Position C.1.1 of Regulatory Guide (RG) 1.29, "Seismic Design Classification," as it relates to the seismic classification of facility components. In accordance with SRP Section 9.1.1, specific criteria necessary to meet the requirements of GDC 61 and 62 are American Nuclear Society (ANS) 57.1-1980, "Design Requirements for Light Water Reactor Fuel Handling Systems," and ANS 57.3-1981, "Design Requirements for New LWR Fuel Storage Facilities," as they relate to preventing criticality and to aspects of the radiological design. In the AP1000 Design Control Document (DCD) Tier 2, Section 9.1.1, "New Fuel Storage," the applicant provides the design bases, a description, and a safety evaluation of the new fuel storage arrangement for the AP1000 design.

In DCD Tier 2, Section 9.1.1.1, "Design Bases," the applicant states that the new fuel will be stored in a high-density rack that includes integral neutron-absorbing material to maintain the required degree of subcriticality. The rack is designed to store fuel of the maximum design-basis enrichment. The rack will include storage locations for 72 fuel assemblies. The rack array will have a center-to-center spacing of 27.7 cm (10.9 in.). This spacing provides the minimum separation between adjacent fuel assemblies that is sufficient to maintain a subcritical array, even if the building is flooded with unborated water or fire extinguishant aerosols, or during any design-basis event. The location of the new fuel storage facility will be within the seismic Category I auxiliary building fuel-handling area. The dry, unlined, approximately 5.2-m (17-ft)-deep reinforced concrete pit is designed to support the new fuel storage rack. The pit floor will support the rack, and the pit wall structures will provide lateral support at the rack top grid structure. The new fuel pit will normally be covered to prevent foreign objects from entering the new fuel storage rack.

In DCD Tier 2, Section 9.1.1.3, "Safety Evaluation," the applicant provides a safety evaluation to demonstrate that the new fuel storage rack design complies with the design bases. DCD Tier 2, Section 9.1.1.3, also states that the new fuel racks are purchased equipment and that the purchase specification will require the vendor to perform a criticality analysis of the new fuel storage racks. The applicant considered normal and postulated accident conditions, such as flooding with pure water and low-density optimum moderator "misting." The following design features minimize the possibility of these accidents:

- travel limits on handling equipment capable of carrying loads heavier than fuel components
- rack designed for safe-shutdown earthquake (SSE) conditions
- rack designed for dropped fuel assembly (and handling tool) conditions
- new fuel storage pit cover to protect new fuel from dropped objects and debris.

In addition, neither the fuel-handling machine nor the cask-handling crane accesses the new fuel pit. This precludes moving loads greater than that of the fuel components over new fuel assemblies.

The staff performed its review in accordance with the guidance and acceptance criteria in SRP Section 9.1.1. The staff directed its evaluation to determine whether the new fuel storage design complies with the requirements of GDC 2, 5, 61, and 62. On the basis of its review, the staff concludes the following:

- The new fuel storage facility will be located within the seismic Category I auxiliary building fuel-handling area in accordance with DCD Tier 2, Section 9.1.1.2, "Facilities Description." The new fuel storage rack is designed to meet the seismic Category I guidance of RG 1.29. Therefore, the staff finds that the new fuel storage facility meets the requirements of GDC 2.

- The AP1000 design can be used at either single-unit or multiple-unit sites. Nonetheless, in DCD Tier 2, Section 3.1.1, "Overall Requirements," the applicant states that the AP1000 design is a single-unit plant and that "if more than one unit were built on the same site, none of the safety-related systems would be shared." Should a multiple-unit site be proposed, the combined license (COL) applicant referencing the AP1000 design will be required to apply for the evaluation of the units' compliance with the requirements of GDC 5, with respect to the capability of shared SSCs important to safety to perform their required safety functions.

- In DCD Tier 2, Section 9.1.1.3, the applicant states that the design of the rack is such that the effective multiplication factor (K_{eff}) remains less than or equal to 0.95 with new fuel of the maximum design-basis enrichment. For a postulated accident condition of flooding the new fuel storage area with unborated water, K_{eff} will not exceed 0.98. DCD Tier 2, Section 4.3.2.6.1, "Criticality Design Method Outside the Reactor," states that the two principal methods of preventing criticality of fuel assemblies outside the reactor are to limit the fuel assembly array size and limit interaction by fixing the minimum separation between assemblies and/or inserting neutron poisons between assemblies. The design basis for preventing criticality outside the reactor is that, including uncertainties, there is a 95-percent probability at a 95-percent confidence level that the K_{eff} of the fuel assembly array will be less than 0.95, as recommended in ANS 57.1 and ANS 57.3. Therefore, the staff finds that the new fuel facility meets the requirements of GDC 61 and 62.

The staff has completed its review of the new fuel storage facility, including the seismic classification, and the protection of fuel inside the fuel storage pit. The new fuel storage facility is located within the seismic Category I auxiliary building fuel-handling area. The staff finds this acceptable to meet the requirements of GDC 2 related to the ability of the facility and the structures housing it to withstand the effects of natural phenomena, such as earthquakes. In addition, in that the AP1000 is a single-unit design, and a COL applicant must comply with GDC 5 for a multiple-unit site, the staff finds that the design has satisfied the requirements of GDC 5 related to whether shared SSCs important to safety are capable of performing required safety functions. Based on the analysis described above, the staff also finds that the design has met the requirements of GDC 61 related to the facility design for fuel storage and the requirements of GDC 62 related to the prevention of criticality.

9.1.2 Spent Fuel Storage

The staff reviewed the spent fuel storage capability in accordance with SRP Section 9.1.2, "Spent Fuel Storage." The staff's acceptance of the spent fuel storage facility is based on compliance with the following requirements:

- GDC 2, as it relates to the ability of the facility and the structures housing it to withstand the effects of natural phenomena, such as earthquakes, tornados, and hurricanes

- GDC 4, "Environmental and Dynamic Effects Design Bases," as it relates to the ability of the facility and the structures housing it to withstand the effects of external missiles, and internally-generated missiles, pipe whip, jet impingement forces, and adverse environmental conditions associated with pipe breaks, such that safety functions will not be impaired

- GDC 5, as it relates to whether shared SSCs important to safety are capable of performing required safety functions

- GDC 61, as it relates to the facility design for fuel storage and handling of radioactive materials

- GDC 62, as it relates to the prevention of criticality

- GDC 63, "Monitoring Fuel and Waste Storage," as it relates to monitoring systems provided to detect conditions that could result in the loss of decay heat removal capabilities, to detect excessive radiation levels, and to initiate appropriate safety actions

In accordance with SRP Section 9.1.1, compliance with the requirements of GDC 2 depends on adherence to the guidance of Regulatory Position C.3 of RG 1.13, "Spent Fuel Storage Facility Design Basis"; the applicable portions of RG 1.29 and RG 1.117, "Tornado Design Classification"; and paragraphs 5.1.1, 5.1.3, 5.1.12, 5.3.2, and 5.3.4 of ANS 57.2-1976, "Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations." Compliance with the requirements of GDC 4 depends on adherence to the guidance of Regulatory Position C.3 of RG 1.13, as well as RG 1.115, "Protection Against Low-Trajectory Turbine Missiles," and RG 1.117, and the appropriate paragraphs of ANS 57.2. Compliance with the requirements of GDC 61 depends on adherence to the guidance of Positions C.1 and C.4 of RG 1.13, the appropriate paragraphs of ANS 57.2, and adherence to the fuel storage capacity guidelines noted in Subsection III.1 of SRP Section 9.1.2. Compliance with the requirements of GDC 62 depends on adherence to the guidance of Positions C.1 and C.4 of RG 1.13, as well as the appropriate paragraphs of ANS 57.2. Finally, compliance with the requirements of GDC 63 depends on adherence to the guidance of paragraph 5.4 of ANS 57.2.

In DCD Tier 2, Section 9.1.2, "Spent Fuel Storage," the applicant presents the design bases, facilities description, and a safety evaluation of the spent fuel storage arrangement. In addition, the applicant indicates that the spent fuel will be stored in high-density racks that include integral, neutron-absorbing material to maintain the required degree of subcriticality. The racks are designed to store fuel of the maximum design-basis enrichment. The rack arrays will have a center-to-center spacing of 27.7 cm (10.9 in.) and storage locations for 619 fuel assemblies. In addition, the rack module will contain integral storage locations for five defective fuel storage containers. The spent fuel storage racks, which will be seismic Category I, will be located within the spent fuel pool (SFP). The racks will consist of an array of cells interconnected to each other at several elevations and to supporting grid structures at the top and bottom elevations. The rack modules will be free-standing, neither anchored to the pool floor nor braced to the pool wall.

The spent fuel storage facility (spent fuel pool) will be within the seismic Category I auxiliary building fuel-handling area. The DCD states that the facility will be protected from the effects of natural phenomena, such as earthquakes, wind, tornados, floods, and external missiles. DCD Tier 2, Section 9.1.1.2, "Facilities Description," also indicates, and the staff agrees, that internally-generated missiles are of no concern because the fuel-handling area does not contain any credible sources of internally-generated missiles. As a result, the staff has determined that the spent fuel storage design meets the applicable guidance of RGs 1.115 and 1.117.

In DCD Tier 2, Section 9.1.2.3, "Safety Evaluation," the applicant provides a safety evaluation to demonstrate that the spent fuel storage rack design and location comply with its design bases. The safety evaluation includes postulated accidents and criticality safety assumptions. The applicant considered the following postulated accidents:

- fuel-handling accidents (e.g., dropped fuel assembly)
- uplift force on the fuel racks
- a misplaced fuel assembly

The following design features minimize the possibility of these accidents:

- The design of the cask handling crane (capable of carrying loads heavier than the fuel components) prevents it from carrying loads over the fuel storage area.

- The racks are designed for SSE conditions.

- The racks are designed for dropped fuel assembly (and handling tool) conditions.

- The fuel-handling machine is designed to seismic Category I requirements.

In DCD Tier 2, Section 9.1.2.3, "Safety Evaluation," the applicant states that the design of the racks is such that K_{eff} remains less than or equal to 0.95 under design-basis conditions, including fuel-handling accidents. DCD Tier 2, Section 4.3.2.6.1, "Criticality Design Method Outside the Reactor," states that the two principal methods of preventing criticality of fuel assemblies outside the reactor are to (1) limit the fuel assembly array size, and (2) limit interaction by fixing the minimum separation between assemblies and/or inserting neutron poisons between assemblies. The design basis for preventing criticality outside the reactor is that, including uncertainties, there is a 95-percent probability at a 95-percent confidence level that the K_{eff} of the fuel assembly array will be less than 0.95, as recommended in ANS 57.1 and ANS 57.3. Therefore, the staff finds that the spent fuel storage design meets the requirements of GDC 61 and 62.

Section 9.1.3 of this report discusses the staff's evaluation regarding the spent fuel storage design's compliance with the requirements of GDC 63.

The staff based its review of DCD Tier 2, Section 9.1.2, on the guidance and acceptance criteria in SRP Section 9.1.2. The staff directed its evaluation at determining whether the spent fuel storage facility complies with the requirements of GDC 2, 4, 5, 61, 62, and 63. Meeting these criteria depends on conformance to Positions C.1, C.3, and C.4 of RG 1.13; applicable portions of RGs 1.29, 1.115, and 1.117; and the appropriate paragraphs of ANS 57.2. On the basis of its review, the staff concludes the following:

- In accordance with Regulatory Position C.3 of RG 1.13, the system design prevents heavy loads from being lifted over the SFP. In addition, the fuel racks are designed to withstand a load drop equivalent to that from a fuel assembly and its associated handling tool when dropped from its operating height.

- In accordance with Regulatory Position C.1 of RG 1.13, RG 1.29, and paragraphs 5.1.1, 5.1.3, 5.1.12, and 5.3.2 of ANS 57.2, the spent fuel storage racks are in the spent fuel storage pool, which is within the seismic Category I auxiliary building fuel-handling area. The auxiliary building is designed to maintain its structural integrity following an SSE and to perform its intended function following a postulated event, such as a fire. The SFP and racks are designed to seismic Category I requirements.

- In accordance with Regulatory Position C.4 of RG 1.13, the spent fuel storage facility is located within the seismic Category I auxiliary building fuel-handling area. The radiologically controlled area ventilation system (VAS) serves this portion of the auxiliary building. The VAS consists of a fuel-handling area ventilation subsystem and an auxiliary/annex building ventilation subsystem. As stated in DCD Tier 2, Table 3.2-3, the VAS is nonseismic. The VAS serves no safety-related function. Section 9.4 of this report discusses the staff's review of the VAS.

For the reasons described above, the staff finds that the spent fuel storage design complies with the requirements of GDC 2, as they relate to the ability of the facility and the structures housing it to withstand the effects of natural phenomena, such as earthquakes, tornados, and hurricanes. The staff finds that the spent fuel storage design complies with the requirements of GDC 4, as they relate to the ability of the facility and the structures housing it to withstand the effects of external missiles, pipe whip, jet impingement forces, and adverse environmental conditions associated with pipe breaks, such that safety functions will not be impaired. DCD Tier 2, Section 9.1.1.2.1, Item E, states, and the staff agrees, that internally-generated missiles are of no concern because the fuel-handling area does not contain any credible sources of internally-generated missiles.

In addition, because the AP1000 is a single-unit design, and a COL applicant must comply with GDC 5 for a multiple-unit site, the staff finds that the spent fuel storage design satisfies the requirements of GDC 5 as they relate to whether shared SSCs important to safety are capable of performing their required safety functions. The staff finds that the spent fuel storage design is in compliance with the requirements of GDC 61, as they relate to the facility design for fuel storage and handling radioactive materials, and GDC 62, as they relate to the prevention of criticality. In addition, the spent fuel storage design complies with the requirements of GDC 63, as discussed in Section 9.1.3 of this report, as they relate to monitoring systems provided to detect conditions that could result in the loss of decay heat removal capabilities, to detect excessive radiation levels, and to initiate appropriate safety actions.

9.1.3 Spent Fuel Pool Cooling and Purification

The staff has reviewed the SFP cooling and purification system (SFPCPS) in accordance with SRP Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System." The staff's acceptance of the SFPCPS design is based on compliance with the following SRP guidance:

- GDC 2, as it relates to the ability of the system and the structures housing it to withstand the effects of natural phenomena, such as earthquakes, tornados, and hurricanes

- GDC 4, as it relates to the ability of the system and the structures housing it to withstand the effects of external missiles

- GDC 5, as it relates to whether shared SSCs important to safety are capable of performing required safety functions

- GDC 44, "Cooling Water," as it relates to the following:

    - the system's ability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions

  - suitable redundancy of components so that safety functions can be performed assuming a single active failure of a component coincident with a loss of offsite power (LOOP) event
  - the system's ability to isolate components, systems, or piping so that they do not compromise the system's safety function

- GDC 45, "Inspection of Cooling Water System," as it relates to allowing periodic inspection of safety-related components and equipment
- GDC 46, "Testing of Cooling Water System," as it relates to allowing operational functional testing of safety-related systems or components to ensure structural integrity and system leaktightness, operability, and adequate performance of active system components, as well as the capability of the integrated system to perform the required functions during normal, shutdown, and accident conditions
- GDC 61, as it relates to the following system design criteria for fuel storage and handling of radioactive materials:
  - capability for periodic testing of components important to safety
  - provisions for containment
  - provisions for decay heat removal
  - capability to prevent reduction in fuel storage coolant inventory under accident conditions in accordance with Regulatory Position C.6 of RG 1.13
  - capability and capacity to remove corrosion products, radioactive materials, and impurities from the pool water and reduce occupational exposures
- GDC 63, as it relates to monitoring systems provided to detect conditions that could result in the loss of decay heat removal capabilities, detect excessive radiation levels, and initiate appropriate safety actions
- Title 10, Section 20.1101(b), of the Code of Federal Regulations (10 CFR 20.1101(b)), as it relates to radiation doses being kept as low as is reasonably achievable (ALARA)

Compliance with the requirements of GDC 2 depends on adherence to the guidance of Positions C.1, C.2, C.6, and C.8 of RG 1.13, as well as Regulatory Position C.1 (safety-related portions of the system) and Regulatory Position C.2 (non-safety-related portions of the system) of RG 1.29. Compliance with the requirements of GDC 4 depends on adherence to the guidance of Regulatory Position C.2 of RG 1.13. Compliance with the requirements of GDC 44 depends on adherence to the recommendations of SRP Branch Technical Position (BTP) Auxiliary Systems Branch (ASB) 9-2, "Residual Decay Energy for Light Water Reactors for Long-Term Cooling," for calculating the heat loads, the assumptions set forth in Item 1.h of Subsection III of SRP Section 9.1.3, and the pool temperature limitations identified in Item 1.d of Subsection III of SRP Section 9.1.3. Compliance with the requirements of 10 CFR 20.1101(b) depends on adherence to the guidance of Positions C.2(f)(2) and C.2.f(3) of

RG 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable."

In DCD Tier 2, Section 9.1.3.2, "System Description," the applicant states that the SFP cooling system is a non-safety-related system. The water in the pool performs the safety-related function of cooling and shielding the fuel in the SFP. DCD Tier 2, Figure 9.1-5, provides a simplified sketch of the system.

The applicant states that the SFP cooling system consists of two mechanical trains of equipment. Each train consists of one SFP pump, one SFP heat exchanger, one SFP demineralizer, and one SFP filter. The two trains of equipment share common suction and discharge headers. In addition, the SFP cooling system comprises piping, valves, and instrumentation necessary for system operation. Either train of equipment can perform any of the functions required of the SFP cooling system independently of the other train. One train is continuously cooling and purifying the SFP, while the other train is available for water transfers or in-containment refueling water storage tank (IRWST) purification or is aligned as a backup to the operating train of equipment.

Both trains are designed to process SFP water. Each pump takes suction from the common suction header and discharges directly to its respective heat exchanger. The outlet piping branches into parallel lines. The purification branch is designed to process approximately 20 percent of the cooling flow, while the bypass branch passes the remaining. Each purification branch is routed directly to a SFP demineralizer. The outlet of the demineralizer is routed to a SFP filter. The outlet of the filter then connects to the bypass branch, which forms a common line that connects to the discharge header.

The SFP cooling system suction header connects to the SFP at two locations. The main suction line connects to the SFP at an elevation 0.6 m (2 ft) below the normal water level of the pool. Two skimmer connections take suction from the water surface of the SFP. This suction arrangement prevents the SFP from inadvertently being drained below a level that would prevent the water in the SFP from performing its safety functions. This arrangement also eliminates the need for a separate skimmer circuit arrangement.

The SFP pump suction header connects to the IRWST and the refueling cavity. This enables purification of the IRWST or the refueling cavity and allows for the transfer of water between the IRWST and the refueling cavity. The SFP pump suction header also connects to the fuel transfer canal and the cask loading pit. The purpose of these connections is primarily to transfer water from the fuel transfer canal to the cask loading pit. Water that is normally stored in the fuel transfer canal can be sent to the cask loading pit and from the cask loading pit back to the transfer canal.

The SFP is initially filled with water having a boron concentration of approximately 2500 parts per million (ppm). For makeup purposes, including replacement of evaporative losses, the demineralized water transfer and storage system provides demineralized water to the SFP. Boron may be added to the SFP from the chemical and volume control system (CVS).

A gate may be used to separate the SFP water from the water in the transfer canal. The gate enables drainage of the transfer canal to permit maintenance of the fuel transfer equipment.

The staff reviewed the SFPCPS for compliance with the requirements of GDC 2, 4, 5, 44, 45, 46, 61, and 63 and 10 CFR 20.1101(b), as referenced in SRP Section 9.1.3. The staff finds that the AP1000 SFPCPS is not a safety-related system and is not required to operate following events such as earthquakes, fires, passive failures, or multiple active failures. The SFPCPS has the safety-related functions of providing containment isolation and providing safety-related connections for temporary emergency makeup to the SFP for cooling. Seismically qualified safety-related makeup connections from the passive containment cooling system (PCS) can provide SFP makeup for a long-term station blackout. These connections are in an area of the auxiliary building that operating personnel can access without being exposed to excessive levels of radiation or adverse environmental conditions during boiling of the pool.

In the design of the SFP, water is maintained above the spent fuel assemblies for at least 7 days following a loss of the SFP cooling system. In accordance with the design, the minimum water level to achieve sufficient cooling is the subcooled, collapsed level (without vapor voids) required to cover the top of the fuel assemblies. Therefore, the applicable portion of the GDC 2 requirements is that the structure housing the system must be able to withstand the effects of natural phenomena, such as earthquakes, tornados, and hurricanes. Because the SFP is located in a seismic Category I building in the fuel-handling area, the staff has determined that the SFPCPS is protected from natural phenomena and complies with Regulatory Positions C.1, C.2, C.6, and C.8 of RG 1.13 and Regulatory Positions C.1 and C.2 of RG 1.29. Thus, the staff concludes that the SFPCPS complies with the requirements of GDC 2. The SFPCPS is also in compliance with the applicable portions of the following requirements:

- GDC 4, as it relates to the ability of the structure housing the system to withstand the effects of external missiles

  The SFP is located in a seismic Category I building. Therefore, the SFPCPS is protected from external missiles. Thus, the staff concludes that the SFPCPS complies with Regulatory Position C.4 of RG 1.13 and thus the requirements of GDC 4.

- GDC 5, as it relates to whether shared SSCs important to safety are capable of performing required safety functions

  In that the AP1000 is a single-unit design, and a COL applicant must comply with GDC 5 for a multiple-unit site, the staff finds that the SFPCPS complies with the requirements of GDC 5.

- GDC 44, as it relates to the system's ability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions

  There are no safety-related SSCs involved in the SFP system under normal operating conditions; however, during accident conditions, the SFP is designed to cool by boiling and transferring the heat to the atmosphere. Therefore, the SFPCPS meets the intent of BTP ASB 9-2, thereby meeting the intent of GDC 44.

- GDC 45, as it relates to allowing periodic inspection of safety-related components and equipment

The spent pool cooling system is not a safety-related system; however, DCD Tier 2, Section 9.1.3.6.2, states that periodic visual inspections and preventive maintenance will be performed. Therefore, the SFPCPS meets the intent of GDC 45.

- GDC 46, as it relates to the capability of the system to perform required functions during normal, shutdown, and accident situations

  As discussed above, the SFPCPS meets the required functions of providing containment isolation and providing safety-related connections for temporary emergency makeup for SFP cooling. Therefore, the SFPCPS meets the intent of GDC 46.

- GDC 61, as it relates to provisions for decay heat removal; the capability to prevent reduction in fuel storage coolant inventory under accident conditions; and the capability and capacity to remove fission products, radioactive materials, and impurities from the pool water and reduce occupational exposures

  Under accident conditions, the system is designed to provide makeup water for 7 days. In addition, the staff finds the purification system acceptable to remove fission products and radioactive materials from the pool water, thereby reducing occupational exposures. Thus, the staff concludes that the SFPCPS complies with the requirements of GDC 61.

- GDC 63, as it relates to monitoring systems provided to detect conditions that could result in the loss of decay heat removal capabilities, detect excessive radiation levels, and initiate appropriate safety actions

  The AP1000 design provides acceptable instrumentation to measure temperature, pressure, flow, and level in the SFP. The design also limits exposure rates at the surface of the SFP to less than 25 Microsieverts per hour (2.5 millirem per hour (mrem/hr)). This corresponds to an activity level in the water of approximately 0.005 microcurie per gram for the dominant gamma-emitting isotopes at the time of refueling. The SFP cooling system flow rate for one train shall exceed the rate necessary to provide two water volume changes in 24 hours for the SFP water. Therefore, the staff concludes that the SFPCPS complies with the requirements of GDC 63.

- The requirements of 10 CFR 20.110(b), as they relate to the design of the fuel pool cooling system purification capability to minimize the occupational radiation exposure and thereby keeping radiation doses ALARA

  The staff finds that the SFP cooling system provides a purification and filtration system design that will minimize the occupational radiation exposure, thereby keeping radiation doses ALARA, and meeting the intent of RG 8.8. Accordingly, the staff concludes that the SFPCPS complies with the requirements of 10 CFR 20.110(b).

On the basis of the preceding findings, the staff concludes that the information provided by the applicant regarding the design of the SFPCPS is acceptable.

9.1.4 Light-Load Handling System (Related to Refueling)

The staff reviewed the light-load handling system (LLHS) in accordance with SRP Section 9.1.4, "Light Load Handling System." Staff acceptance of the design of the system is contingent on compliance with the following requirements:

- GDC 2, as it relates to the ability of SSCs to withstand the effects of earthquakes
- GDC 5, as it relates to whether shared SSCs important to safety are capable of performing required safety functions
- GDC 61, as it relates to a radioactivity release resulting from fuel damage and the avoidance of excessive personnel radiation exposure
- GDC 62, as it relates to criticality accidents

In accordance with SRP Section 9.1.4, compliance with the requirements of GDC 2 depends on adherence to the guidance of Regulatory Positions C.1 and C.6 of RG 1.13, as well as Positions C.1 and C.2 of RG 1.29. In accordance with SRP Section 9.1.4, compliance with the requirements of GDC 61 depends on adherence to the guidance of Regulatory Position C.3 of RG 1.13, as well as ANS 57.1/ANSI-N208. In accordance with SRP Section 9.1.4, compliance with the requirements of GDC 62 depends on adherence to the guidance of Regulatory Position C.3 of RG 1.13, as well as ANS 57.1/ANSI-N208.

In DCD Tier 2, Section 9.1.4.2, the applicant states that the LLHS consists of the equipment and structures needed for the refueling operation. This equipment includes fuel assemblies, core component and reactor component hoisting equipment, handling equipment, and a *dual-basket fuel transfer system. The following structures are associated with the fuel-handling* equipment:

- *refueling cavity*
- transfer canal
- fuel transfer tube
- SFP
- cask loading area
- new fuel storage area
- new fuel receiving and inspection area

The fuel-handling equipment is designed to handle the spent fuel assemblies underwater from the time they leave the reactor vessel until they are placed in a container for shipment from the site. As described below, underwater transfer of spent fuel assemblies provides an effective and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. The boric acid concentration in the water is sufficient to preclude criticality.

The associated fuel-handling structures may be generally divided into two areas:

- the refueling cavity, which is flooded only during plant shutdown for refueling
- the SFP and transfer canal, which are kept full of water

The fuel transfer tube, which is fitted with a quick-opening hatch on the canal end and a valve on the fuel storage area end, connects the refueling cavity and fuel storage area. The hatch is in place, except during refueling, to provide containment integrity. An underwater transfer car carries fuel through the tube.

The refueling machine moves fuel between the reactor vessel and the fuel transfer system. The fuel transfer system moves up to two fuel assemblies at a time between the containment building and the auxiliary building fuel-handling area. After a fuel assembly is placed in the fuel container, the lifting arm pivots the fuel assembly to the horizontal position for passage through the seismic Category I fuel transfer tube, in accordance with Regulatory Positions C.1 and C.6 of RG 1.13 and Regulatory Positions C.1 and C.2 of RG 1.29. After the transfer car transports the fuel assembly through the transfer tube, the lifting arm at that end of the tube pivots the assembly to a vertical position so that the assembly can be lifted out of the fuel container.

In the fuel-handling area, the seismic Category I fuel-handling machine moves the fuel assemblies, in accordance with Regulatory Positions C.1 and C.6 of RG 1.13 and Regulatory Positions C.1 and C.2 of RG 1.29. Initially, a short tool is used to handle new fuel assemblies, but the new fuel elevator must be used to lower the assembly to a depth at which the fuel-handling machine can place the new fuel assemblies into or out of the spent fuel storage racks.

The seismic Category II new fuel jib crane removes new fuel assemblies received for refueling one at a time from the shipping container and moves them into the new fuel assembly inspection area.

DCD Tier 2, Section 9.1.4.1.1, "Safety Design Basis," states that in the event of an SSE, handling equipment cannot fail in such a manner as to prevent the required function of seismic Category I equipment. On the basis of the preceding discussion, the staff concludes that the LLHS complies with the requirements of GDC 2.

The transfer car controls for the fuel transfer system are located in the fuel-handling area. Therefore, conditions in the containment are not visible to the operator. The transfer car permissive switch allows the fuel transfer system containment operator to exercise some control over car movement, if conditions visible to the operator warrant such control.

In accordance with Regulatory Position C.3 of RG 1.13 and ANS 57.1/ANSI-N208, an interlock on the fuel transfer system prevents the upender from being moved from the horizontal to the vertical position if the transfer car has not reached the end of its travel. An interlock on the transfer tube valve permits transfer car operation only when the transfer tube valve position switch indicates that the valve is fully open.

The fuel transfer system is also interlocked with the refueling machine. Whenever the transfer car is located in the refueling cavity, the fuel transfer system cannot be operated unless the refueling machine mast is in the fully retracted position, the refueling machine is over the core, or the gripper is released and inside the core.

On the SFP side, the fuel transfer system is interlocked with the fuel-handling machine. The fuel transfer system cannot be operated until the fuel-handling machine is moved away from the fuel transfer system area.

Fuel-handling tools and equipment handled over an open reactor vessel are designed to prevent inadvertent decoupling from machine hooks. In addition, lifting rigs are pinned to the machine hook, and hook supporting tools have safety latches. Tools required for handling internal reactor components are designed with the following fail-safe features that prevent disengagement of the component in the event of operating mechanism malfunction:

- The air cylinders actuating the gripper mechanism are equipped with backup springs that close the gripper in the event of loss of air to the cylinder. Air-operated valves are equipped with safety locking rings to prevent inadvertent actuation.

- When the fingers are latched, the actuating handle is positively locked, preventing inadvertent actuation. The tool is preoperationally tested at 125 percent of the weight of one fuel assembly.

During spent fuel transfer, the gamma dose rate at the surface of the water is 20 mrem/hr or less, achieved by maintaining a minimum of 3 m (10 ft) of water above the top of the active fuel height during handling operations. The three fuel-handling devices used to lift spent fuel assemblies are the refueling machine, the fuel-handling machine, and the spent fuel-handling tool. Both the refueling machine and fuel-handling machine contain positive stops that prevent the fuel assembly from being raised above a safe shielding height.

DCD Tier 2, Section 9.1.4.1.1, states that the fuel-handling devices have provisions to avoid dropping or jamming fuel assemblies during transfer operation and that the handling equipment has provisions to avoid dropping fuel-handling devices during the fuel transfer operation. On the basis of the preceding discussion, the staff concludes that the LLHS meets the intent of GDC 61 and 62.

The staff finds that the LLHS for the AP1000 design complies with GDC 2, as it relates to the ability of SSCs to withstand the effects of an earthquake. The LLHS complies with GDC 5, as it relates to whether shared SSCs important to safety can perform their required safety functions, in accordance with DCD Tier 2, Section 3.1.1, which states, "The AP1000 is a single-unit plant. If more than one unit were built on the same site, none of the safety-related systems would be shared." The LLHS also complies with the intent of GDC 61 and 62, as related to a radioactivity release resulting from fuel damage and the avoidance of excessive personnel radiation exposure, and criticality accidents, respectively.

9.1.5 Overhead Heavy-Load Handling Systems

The staff's acceptance of the design of a heavy-load handling systems (HLHSs) is contingent on compliance with the following requirements:

- GDC 2, as it relates to the ability of SSCs to withstand the effects of natural phenomena such as earthquakes

- GDC 4, as it relates to the protection of safety-related equipment from the effects of internally-generated missiles (i.e., dropped loads)

- GDC 5, as it relates to whether shared SSCs important to safety are capable of performing their required safety functions

- GDC 61, as it relates to the safe handling and storage of fuel

Compliance with the requirements of GDC 2 depends on adherence to the guidance of Regulatory Positions C.1 and C.6 of RG 1.13, as well as Regulatory Positions C.1 and C.2 of RG 1.29. Compliance with the requirements of GDC 4 depends on adherence to the guidance of Regulatory Positions C.3 and C.5 of RG 1.13. Other guidelines used in the evaluation of this system include NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," issued in July 1980.

For the AP1000 design, the applicant defines a heavy load to be one that weighs more than the combined weight (about 1406 kg (3100 lbs)) of a fuel assembly with a rod cluster control, and the associated handling device (consisting of the inner mast of the fuel-handling machine and the fuel-gripper assembly). This equipment is part of the mechanical handling system (MHS) and is located throughout the plant. An HLHS is generally classified as a non-safety-related, nonseismic system. The components of single-failure-proof systems necessary to prevent uncontrolled lowering of a critical load are classified as safety-related.

The containment polar crane, the equipment hatch hoist system, and the maintenance hatch hoist system are single-failure-proof systems. Classified as seismic Category I, they are designed to support a critical load during and after an SSE and thus are in compliance with Regulatory Positions C.1 and C.6 of RG 1.13 and Regulatory Positions C.1 and C.2 of RG 1.29. A critical load is a heavy load that, if dropped, could cause unacceptable damage to reactor fuel elements, or a loss of safe shutdown or decay heat removal capability. Therefore, the staff concludes that the HLHSs comply with the requirements of GDC 2.

For the AP1000 design, the plant arrangement and the design of HLHSs reflect on the following criteria:

- In accordance with Regulatory Positions C.3 and C.5 of RG 1.13, to the extent practicable, the system does not carry heavy loads over or near safety-related components, including irradiated fuel and safe-shutdown components. Safe load paths are designed for heavy load handling in safety-related areas.

- In accordance with the guidance of NUREG-0612:

  - The likelihood of a load drop is extremely small (that is, the handling system is single-failure proof), or the consequences of a postulated load drop are within acceptable limits.

  - Single-failure-proof systems can stop and hold a critical load following the credible failure of a single component.

  - Single-failure-proof systems can support a critical load during and after an SSE.

Except for the containment polar crane, the equipment hatch hoist system, and the maintenance hatch hoist system, the HLHSs are not single-failure proof. The DCD states that overhead cranes are designed according to American Society of Mechanical Engineers

(ASME) NOG-1, "Rules for Construction of Overhead and Gantry Cranes." The design of other cranes and hoists handling heavy loads follows applicable ANSI standards.

In DCD Tier 2, Section 9.1.5.3, the applicant states that for the polar crane and the equipment and maintenance hatch hoist systems, the design provides redundancy for load-bearing components, such as hoisting ropes, sheaves, equalizer assembly, hooks, and holding brakes. These systems are designed to support a critical load during and after an SSE.

The spent fuel shipping cask storage pit is separate from the SFP. The spent fuel shipping cask crane cannot move over the SFP because the crane rails do not extend over the pool. Mechanical stops prevent the spent fuel shipping cask crane from going beyond the ends of the rails.

In DCD Tier 2, Section 9.1.5.3, the applicant also states that a heavy load analysis evaluates postulated load drops from HLHSs located in safety-related areas of the plant, specifically the nuclear island. The applicant further states that critical loads handled by the single-failure-proof containment polar crane, equipment hatch hoist, or maintenance hatch hoist do not require evaluations, because a load drop is unlikely. In accordance with NUREG-0612, the purpose of the heavy load analysis is to confirm that a postulated load drop does not cause unacceptable damage to reactor fuel elements or a loss of safe shutdown or decay heat removal capability. For these reasons, the staff concludes that the HLHSs comply with the requirements of GDC 61.

As described above, the staff concludes that the design of the AP1000 HLHSs comply with the requirements of GDC 2, as they relate to the ability of SSCs to withstand the effects of natural phenomena, such as earthquakes. The HLHSs also comply with GDC 4, as it relates to protection of safety-related equipment from the effects of internally-generated missiles, because in DCD Tier 2, Section 9.1.1.2.1, Item E, the applicant stated that the fuel-handling area does not contain any credible sources of internally-generated missiles. In that the AP1000 is a single-unit design, and a COL applicant must comply with GDC 5 for a multiple-unit site, the staff finds that the HLHSs comply with the requirements of GDC 5, relating to whether shared SSCs important to safety can perform their required safety functions. The design of the HLHSs is also in compliance with GDC 61, as it relates to the safe handling and storage of fuel.

9.1.6 Combined License Information Items

In DCD Tier 2, Section 9.1.6, "Combined License Information for Fuel Storage and Handling," Westinghouse describes the following COL Action Items: (note that the NRC staff action item number is after each Westinghouse item)

The Combined License applicant is responsible for a confirmatory structural dynamic and stress analysis for the new fuel rack as described in DCD Tier 2, Section 9.1.1.2.1. This is COL Action Item 9.1.6-1.

The Combined License applicant is responsible for a confirmatory criticality analysis for the new fuel rack, as described in DCD Tier 2, Section 9.1.1.3. This analysis should address the degradation of integral neutron absorbing material in the new fuel pool storage racks as identified in GL 96-04, and assess the integral neutron absorbing material capability to maintain a 5-percent subcriticality margin. This is COL Action Item 9.1.6-2.

The Combined License applicant is responsible for a confirmatory structural dynamic and stress analysis for the spent fuel racks, as described in DCD Tier 2, Section 9.1.2.2.1. This includes reconciliation of loads imposed by the spent fuel racks on the spent fuel pool structure described in DCD Tier 2, Section 3.8.4. This is COL Action Item 9.1.6-3.

The Combined License applicant is responsible for a confirmatory criticality analysis for the spent fuel racks, as described in DCD Tier 2, Section 9.1.2.3. This analysis should address the degradation of integral neutron absorbing material in the spent fuel pool storage racks as identified in GL 96-04, and assess the integral neutron absorbing material capability to maintain a 5-percent subcriticality margin. This is COL Action Item 9.1.6-4.

The Combined License applicant is responsible for a program for inservice inspection of the light load handling system as specified in DCD Tier 2, Section 9.1.4.4 and the overhead heavy load handling system in accordance with ANSI B30.2, ANSI B30.9, ANSI N14.6, and ASME NOG-1 as specified in DCD Tier 2, Section 9.1.5.4. This is COL Action Item 9.1.6-5.

The Combined License applicant/holder is responsible to ensure an operation radiation monitor is mounted on any crane or fuel handling machine when it is handling fuel. This is COL Action Item 9.1.6-6.

9.2 Water Systems

The following sections describe the staff's review of the AP1000 water systems:

- 9.2.1, "Service Water System"
- 9.2.2, "Component Cooling Water System"
- 9.2.3, "Demineralized Water Treatment System"
- 9.2.4, "Demineralized Water Transfer and Storage System"
- 9.2.5, "Potable Water System"
- 9.2.6, "Sanitary Drainage System"
- 9.2.7, "Central Chilled Water System"
- 9.2.8, "Turbine Building Closed Cooling System"
- 9.2.9, "Waste Water System"
- 9.2.10, "Hot Water Heating System"

Either single-unit or multiple-unit sites can use the AP1000 design. Nonetheless, in DCD Tier 2, Section 3.1.1, the applicant states that the AP1000 design is a single-unit plant, and if more than one unit is built on the same site, multiple units will not share the safety-related systems. Should a multiple-unit site be proposed, the COL applicant referencing the AP1000 design will be required to apply for the evaluation of the units' compliance with the requirements of GDC 5, "Sharing of Structures, Systems, and Components," with respect to the capability of shared SSCs to perform their required safety functions.

9.2.1 Service Water System

The staff reviewed the design of the service water system (SWS) in accordance with SRP Section 9.2.1, "Station Service Water System." However, the SWS for the AP1000 differs from that of the traditional pressurized-water reactor (PWR) designs in that the AP1000 SWS is a completely non-safety-related system with no safety-related function. In traditional PWRs, portions of the SWS were required to perform safety-related functions. The AP1000 SWS is a non-safety-related system because the SWS removes heat only from the component cooling water system (CCS) which is not a safety-related system. Section 9.2.2 of this report contains the staff's evaluation of the CCS as non-safety-related. Therefore, the portions of SRP Section 9.2.1 that apply to safety-related systems do not apply to the AP1000 SWS. As for the non-safety-related SWS meeting the requirements of GDC 2, as they relate to structures and systems being capable of withstanding the effects of natural phenomena, acceptance depends on meeting the guidance of the portions of Regulatory Position C.2 of RG 1.29 regarding non-safety-related systems.

The SWS supplies cooling water to remove heat from the CCS heat exchangers which are located in the turbine building. The system consists of two 100-percent capacity cooling trains of components and piping for normal power operation. Each train includes one service water pump, one component cooling heat exchanger, one strainer, and one cooling tower cell. Because of cross-connections between the trains upstream and downstream of the heat exchangers, either service water pump can supply cooling water to either heat exchanger, and either heat exchanger can discharge to either cooling tower. The cooling tower, cooling tower fans, pumps, and applicable valves of the SWS are classified as AP1000 Class D, seismic Category NS (nonseismic). To provide reasonable assurance that the SWS is operable during anticipated events, the applicant included it in the AP1000 programs, "Investment Protection Short-Term Availability Controls" and "Design Reliability Assurance Program."

The investment protection short-term availability controls (IPSAC), as described in AP1000 DCD Tier 2, Section 16.3, "Investment Protection," define the following:

- equipment that should be operable
- operational modes when the equipment should be operable
- testing and inspections that should be used to demonstrate the equipment's operability
- operational modes that should be used for planned maintenance operations
- remedial actions that should be taken if the equipment is not operable

The Design Reliability Assurance Program (D-RAP), as described in AP1000 DCD Tier 2, Section 17.4, "Design Reliability Assurance Program," provides confidence that equipment remains available and reliable throughout plant life through the Maintenance Rule (10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants").

The service water pumps are centrifugal pumps driven by electric motors. Each pump has a design flow rate of 34.1 m^3/min (9000 gpm). These pumps take suction from the service water pump basin through fixed screens to the pump suction piping. The service water pumps discharge through strainers to the CCS heat exchangers. The heated SWS water from the heat exchangers passes through the discharge piping to the mechanical draft cooling tower, where the system heat is rejected. The cool water, collected in the tower basin, provides the source for the suction of service water pumps.

The power supplies for the SWS pumps and associated active components are from independent and non-safety-related electrical buses. One of two onsite standby diesel generators (DGs) can supply each bus. In the event of loss of normal ac power, the SWS pumps and cooling tower fans, along with the associated motor-operated valves, are automatically loaded onto their associated diesel buses. The SWS, therefore, continues to provide cooling water to the required components during the loss of normal ac power events.

The SWS operates during startup, normal plant operation, normal plant cooldown, and refueling and is available following a LOOP event. Under normal plant operation, one of the two SWS trains removes the heat from one of the two CCS heat exchangers and discharges it to the cooling tower. The standby train automatically starts on combined low-flow and low-pressure values when the operating train fails. During accident conditions, the SWS remains in the same operating modes as for normal operations. Both SWS trains are used during plant startup, shutdown, and refueling.

A radiation monitor with a high alarm checks the service water blowdown flow for potentially radioactive leakage into the SWS from the CCS heat exchangers. Provisions for taking local fluid samples are also available. If radioactive fluid is detected in the SWS, the operator can isolate cooling tower blowdown flow by remote manual control.

With regard to sufficient net positive suction head (NPSH) available for SWS pumps and the potential for water hammer, in DCD Tier 2, Section 9.2.1.2.1, "General Description," the applicant stated that temperatures in the system are moderate and that the pressure of the system is kept above saturation at all locations. The system pressure and temperature relation, and other design features of the system arrangement and control of valves, ensures that sufficient NPSH is available for SWS pumps and minimizes the potential for thermodynamic or transient water hammer.

The maximum ambient air wet bulb temperature specified in DCD Tier 2, Chapter 2, "Site Characteristics," for site interface parameters is 26.67 °C (80 °F). This maximum wet bulb temperature applies to most U.S. plant sites.. Actual site-specific data will dictate design parameters of the cooling tower. Specific site analysis to adjust cooling system capability should accommodate specific site conditions that exceed the 26.67 °C (80 °F) wet bulb temperature.

In DCD Tier 2, Section 9.2.1.1.1, the applicant states that failure of the SWS or its components will not affect the ability of any other safety-related systems to perform their intended safety functions. Postulated breaks in the SWS piping will not impact safety-related components because the SWS is not located in the vicinity of any safety-related equipment, and the water from the break will not reach any safety-related equipment. Therefore, the staff finds that the SWS complies with GDC 2 because it meets the guidance of Regulatory Position C.2 of RG 1.29 for ensuring that the non-safety-related SWS can withstand the effects of earthquakes without affecting safety-related systems.

As described above, the staff has reviewed the SWS in accordance with SRP Section 9.2.1. Because the AP1000 SWS is not safety-related, and its failure does not lead to the failure of any safety systems, the requirements of GDC 4, 44, 45, and 46 and the guidance of SRP Section 9.2.1, regarding safety-related systems, do not apply.

On the basis of the preceding review, the staff finds that the SWS design meets the applicable provisions described in SRP Section 9.2.1. Also, the SWS and its components are classified as

AP1000 Class D and included in the AP1000 IPSAC and D-RAP. Therefore, the staff finds the SWS acceptable.

9.2.2 Component Cooling Water System

The staff reviewed the design of the CCS in accordance with the guidance of SRP Section 9.2.2, "Reactor Auxiliary Cooling Water Systems."

The CCS is a non-safety-related, closed-loop cooling system that transfers heat from various non-safety-related plant components to the SWS during normal plant operation. It also removes heat from various safety-related components (i.e., reactor cooling pumps, CVS letdown heat exchangers, and normal residual heat removal system (RNS) heat exchangers and pumps). However, none of these safety-related components requires cooling water to perform its safety-related functions. The safety-related functions of these components are limited to maintaining primary coolant system integrity and providing reactor coolant pump coastdown capability. The passive core cooling system (PXS) and PCS provide safety-related cooldown and decay heat removal functions.

The CCS provides a barrier to prevent the release of radioactivity from plant components that handle cooling radioactive fluid to the environment. The CCS also provides a barrier against leakage of service water into primary containment and reactor systems.

The CCS consists of two trains and one component cooling water (CCW) surge tank. Each train consists of one CCW pump and one CCW heat exchanger, as well as associated valves, piping, and instrumentation. The CCW surge tank, which accommodates thermal expansion and contraction, connects to a shared portion of the return header. The two trains of equipment take suction from a single return header. The discharge of each heat exchanger is routed directly to the common supply header. This single supply/return header distributes cooling water to the components. Loads inside containment are automatically isolated in response to a safety injection signal which trips the reactor coolant pumps. Individual components, except the reactor coolant pumps, can be isolated locally to permit maintenance, while supplying the remaining components with cooling water.

The two CCW pumps are horizontal, centrifugal pumps. Each pump has a design flow rate of 33.9 m^3/min (8960 gpm). The pumps are redundant for normal operation heat loads. The design-basis cooldown requires both pumps; however, an extended cooldown can be achieved with only one pump in operation. Each pump can be aligned to either heat exchanger. Cooling in the heat exchanger is provided by the SWS. The CCW system pressure is maintained at a higher pressure than the service water to prevent in-leakage from the service water into the system. Three motor-operated isolation valves and a check valve provide containment isolation for the supply and return CCS lines that penetrate the containment barrier. The motor-operated valves are normally open and are closed upon receipt of a safety injection signal.

The power supplies for the CCS pumps and associated active components are independent and are from non-safety-related electrical buses. In the event of loss of normal ac power, the CCS pumps are automatically loaded on the standby diesel. The CCS, therefore, continues to provide cooling water to the required components during the loss of normal ac power events.

The CCS provides cooling water to the safety-related components identified above during normal plant operation and normal reactor shutdown and cooldown. The PXS and PCS provide safety-related cooldown and decay heat removal functions following a loss-of-coolant accident (LOCA). Therefore, the CCS serves no safety-related function, except for containment isolation. Segments of the CCS piping that penetrate the containment and the associated containment isolation valves are safety-related and perform a safety-related containment isolation function. Therefore, these segments are designed to accommodate environmental and dynamic effects associated with pipe breaks, thereby satisfying the requirements of GDC 4. Section 3.6.1 of this report evaluates protection against the effects of pipe breaks, and Section 3.4.1 of this report evaluates protection against internal flooding.

DCD Tier 2, Table 3.2-3, classifies CCS pumps and valves (with the exception of containment isolation valves) as AP1000 Class D, seismic Category NS. In addition, the CCS pumps and valves are included in the AP1000 IPSAC and D-RAP. The containment penetration isolation valves are Safety Class B, as is the pipe between the isolation valves.

On the basis of its review, the staff agrees with the applicant that the CCS does not perform any safety-related function except for containment isolation. Therefore, the portions of SRP Section 9.2.2 that apply to safety-related systems do not apply to the AP1000 CCS.

In DCD Tier 2, Section 9.2.2.1.1, the applicant states that failure of the CCS or its components will not affect the ability of safety-related systems to perform their intended safety functions. This conforms to the guidance of Regulatory Position C.2 of RG 1.29. Therefore, the staff concludes that the CCS complies with the requirements of GDC 2.

GDC 44, 45, and 46 do not apply to the CCS because the CCS heat loads are not safety-related.

The operating temperature of the CCS components will normally be well below 93.3 °C (200 °F), and the pressure will be maintained above atmospheric. Because the CCS will normally operate at temperatures and pressures that prevent formation of steam bubbles, water hammer issues will be avoided.

On the basis of the preceding review, the staff finds that the CCS design meets the applicable provisions described in SRP Section 9.2.2. Also, the CCS is included in the AP1000 IPSAC and D-RAP. Therefore, the staff finds the CCS to be acceptable.

9.2.3 Demineralized Water Treatment System

The staff reviewed DCD Tier 2, Section 9.2.3, "Demineralized Water Treatment System," in accordance with SRP Section 9.2.3, "Demineralized Water Makeup System." The demineralized water treatment system (DTS) is acceptable if the system is capable of providing the required supply of reactor coolant purity water to the demineralized water transfer and storage system (DWS). The DTS does not perform any safety-related function or accident mitigation, and its failure would not reduce the safety of the plant.

9.2.3.1 Summary of Technical Information

The AP1000 DTS receives water from the raw water system (RWS), processes this water to remove ionic impurities, and provides demineralized water to the DWS.

This system consists of the following major components:

- two reverse osmosis (RO) feed pumps
- two 100-percent RO units running in series
- one electrodeionization (EDI) unit for secondary demineralization

DCD Tier 2, Table 9.2.3-1, "Guidelines for Demineralized Water (Measured at the Outlet of the Demineralized Water Treatment System)," provides the system functional specifications for the DTS.

9.2.3.2 Staff Evaluation

The staff evaluated the design and operational requirements of the DTS and concluded that it includes all components associated with the system from the source of raw water to a discharge to the DWS. In addition, the staff reviewed the system functional specifications given in Table 9.2.3-1 to provide the appropriate reactor water coolant purity during all conditions of plant operation. However, high concentrations of halogens and sulfates in the system can accelerate the corrosion of components in the DTS. Therefore, by letter dated September 24, 2002, the staff sent request for additional information (RAI) 281.002 asking the applicant to provide the maximum allowable concentrations of halogens and sulfates in the system. By letter dated October 18, 2002, the applicant responded that the range of halogens and sulfates in this system is shown in Table 9.2.3-1, with the maximum value of 1 part per billion (ppb) for chloride and for sulfate.

The staff concluded that these maximum values for chloride and sulfate are appropriate because these values ensure adequate reactor coolant purity during all conditions of plant operation to keep the levels of corrosion low.

9.2.3.3 Conclusions

The design of the DTS includes the components and piping needed to collect and treat raw water and supply it to the DWS. The staff's review finds that the applicant's proposed design criteria and design bases for the DTS are sufficient to supply adequate reactor coolant purity water during all conditions of plant operation.

9.2.4 Demineralized Water Transfer and Storage System

The staff reviewed the DWS in accordance with the guidance of SRP Section 9.2.3. Specifically, the staff reviewed the system to ensure its capability to provide the required supply of reactor coolant pure makeup water to all systems. Acceptability of the DWS depends on its meeting the guidance of Regulatory Position C.2 of RG 1.29 for non-safety-related systems, the failure of which could affect the functioning of any safety-related system. Conformance with the acceptance criteria of the SRP forms the basis for concluding that the DWS satisfies the applicable requirements of GDC 2, as it relates to the system being capable of withstanding the effects of earthquakes.

The DWS is a non-safety-related system that supplies demineralized water (through the demineralized water storage tank) to fill the condensate storage tank and to the plant systems that demand a demineralized water supply. The DWS primarily consists of a 379-m^3 (100,000-gallon) capacity demineralized water storage tank, a 1,835-m^3 (485,000-gallon) capacity condensate storage tank, two motor-driven demineralized water transfer pumps, and two catalytic oxygen reduction units.

The demineralized water storage tank, which receives water from the DTS, supplies demineralized water to the makeup pumps of the CVS during startup. A low-level alarm on the tank signals the plant operator to isolate demands on the tank, other than the CVS supply. The condensate storage tank serves as a reservoir to supply or receive condensate as required by the condenser hotwell level control system. In the event of loss of main feedwater when the deaerator storage tank is not available, the condensate storage tank will serve as a backup water supply for the startup feedwater pumps. The condensate storage tank will provide sufficient water to the startup feedwater system to permit 8 hours of hot standby operation. Adequate isolation is provided at all makeup demineralized water connections to safety-related systems.

Two catalytic oxygen reduction units degasify the stored demineralized water. One unit is for the demineralized water distribution system, and the other unit is at the condensate storage tank. A check valve, in conjunction with a block valve, prevents backflow of fluids from systems that interface with the DWS. The applicant stated that the condensate storage tank normally contains no significant radioactive contaminants.

The DWS, with the exception of the containment isolation valves, is classified as AP1000 Class D, seismic Category NS. The containment penetration isolation valves are Safety Class B, as is the pipe between the isolation valves.

The system has no safety-related function other than containment isolation, and its failure does not affect the ability of safety-related systems to perform their intended safety functions. Therefore, the design conforms to the guidelines of Regulatory Position C.2 of RG 1.29. Regulatory Position C.1 of RG 1.29 does not apply to the DWS because the system performs no safety-related function.

Based on its review, the staff concludes that the DWS has the capability to provide an adequate supply of reactor coolant pure makeup water to all plant systems during all modes of plant operation. The design of the system complies with Regulatory Position C.2 of RG 1.29 concerning seismic classification and satisfies the applicable requirements of GDC 2 with respect to the need for protection against natural phenomena. Therefore, the staff concludes that the DWS meets the guidance of SRP Section 9.2.3 and, therefore, is acceptable.

9.2.5 Potable Water System

The staff reviewed the potable water system (PWS) in accordance with SRP Section 9.2.4, "Potable and Sanitary Water Systems." Conformance with the acceptance criteria of the SRP forms the basis for concluding that the PWS satisfies GDC 60, "Control of Releases of

Radioactive Materials to the Environment," as it relates to design provisions for controlling the release of water containing radioactive material and preventing contamination of the potable water.

The PWS is a non-safety-related system that is designed to provide clean water from the raw water system for domestic use and human consumption. The system consists of a carbon steel tank with a capacity less than 37.85 m^3 (10,000 gallons), two motor-driven potable water pumps, a system jockey pump, a distribution header around the power block, hot water storage heaters, and necessary interconnecting piping and valves.

The potable water is treated to prevent harmful physiological effects, and its bacteriological and chemical quality conforms to the requirements of the Environmental Protection Agency (EPA) "National Primary Drinking Water Standards" (40 CFR Part 141). Upstream of the potable water storage tank, the turbine island chemical feed system disinfects the raw water supply to the tank. The PWS distribution complies with 29 CFR 1910, "Occupational Safety and Health Standards, Part 141."

In the DCD, the applicant states that no interconnections exist between the PWS and any potentially radioactive system or any system using water for purposes other than domestic water service. To prevent contamination of the PWS from other systems supplied by the RWS, the design of the common supply from the onsite RWS will use either an air gap or reduced-pressure-zone type backflow prevention device. Branches of the PWS supplying plumbing fixtures located in areas of potential radiological hazard where access is restricted are equipped with the reduced-pressure-zone-type backflow prevention devices. Therefore, the design of the PWS satisfies GDC 60, with respect to preventing contamination by the radioactive waste drain system.

On the basis of its review, the staff concludes that the design of the PWS, as described above, satisfies GDC 60, with respect to preventing contamination by radioactive water. Therefore, the staff concludes that the PWS meets the guidance of SRP Section 9.2.4 and, therefore, is acceptable.

9.2.6 Sanitary Drainage System

The staff reviewed the sanitary drainage system (SDS) in accordance with SRP Section 9.2.4. Conformance with the acceptance criteria of the SRP forms the basis for concluding that the SDS satisfies GDC 60, as it relates to design provisions provided control the release of radioactive materials to the environment.

The SDS is a non-safety-related system that collects sanitary wastes from plant restrooms and locker room facilities in the turbine building, auxiliary building, and annex building for treatment, dilution, and discharge. The system is designed to accommodate 0.1 m^3 (25 gallons) per person per day, for up to 500 persons during a 24-hour period. Testing and inspection of the system will be in accordance with the Uniform Plumbing Code Section 318, issued in 2000. The SDS components, such as branch lines, lift stations, and waste treatment plant, are site-specific and outside the scope of the AP1000 design.

In the DCD, the applicant states that the SDS does not serve the facilities in radiologically controlled areas and has no connection to the systems having the potential for containing radioactive material. Therefore, the design of the SDS satisfies GDC 60, with respect to preventing contamination by the radioactive waste drain system.

Based on its review, the staff concludes that the design of the SDS satisfies GDC 60, with respect to control of the release of water containing radioactive material. Therefore, the staff concludes that the SDS follows the guidance of SRP Section 9.2.4 and, therefore, is acceptable.

9.2.7 Central Chilled Water System

The staff reviewed the central chilled water system (VWS) in accordance with SRP Section 9.2.2. Conformance with the acceptance criteria of the SRP forms the basis for concluding that the central chilled water system satisfies GDC 2, 44, 45, and 46.

The VWS is a non-safety-related system that provides chilled water to the cooling coils of the supply air handling units and unit coolers of the following plant heating, ventilation, and air conditioning (HVAC) systems during normal modes of plant operation:

- radiologically controlled area ventilation system
- containment recirculation cooling system
- containment air filtration system
- health physics/control access area HVAC system
- radwaste building ventilation system
- Annex I and auxiliary building nonradioactive ventilation system

The VWS also supplies chilled water to the components of the liquid radwaste system, gaseous radwaste system, containment leak-rate-test system components, secondary sampling system, portable and mobile radwaste system, and electrical switchgear room and personal work area air handling units (AHUs) of the turbine building ventilation system.

The plant HVAC systems require chilled water as a cooling medium to satisfy the ambient temperature requirements for the plant. The CCS supplies the cooling water to the chiller condensers. The VWS is divided into two closed-loop subsystems (i.e., the high-capacity subsystem and the low-capacity subsystem).

The high-capacity subsystem, located in the turbine building, is the primary system to provide chilled water to the major HVAC systems listed above and to other plant equipment requiring chilled water cooling. The high-capacity subsystem consists of two 100-percent capacity chilled water pumps, two 100-percent capacity water-cooled chillers, a chemical feed tank, an expansion tank, and associated valves, piping, and instrumentation.

The high-capacity subsystem is arranged in two parallel trains with common supply and return headers. Each train includes one pump and one chiller. A cross-connection at the discharge of each pump allows for either pump to feed either chiller. During normal operation of the subsystem, one pump/chiller train provides chilled water to plant components at a normal temperature of 4.4 °C (40 °F). The standby train would be started manually if the operating train fails. The design cooling capacity of the high-capacity subsystem is founded on the ambient design temperature of 38 °C (100 °F) dry bulb and 29 °C (77 °F) coincident wet bulb maximum and -23 °C (-10 °F) minimum.

The low-capacity subsystem, located in the auxiliary building, provides chilled water to the HVAC systems in the main control room (MCR), the technical support center (TSC), and the Class 1E electrical equipment room. The low-capacity subsystem consists of two 100-percent capacity chilled water loops, each with a chilled water pump, an air-cooled chiller, an expansion tank, and associated valves, piping, and instrumentation.

This subsystem is arranged in two independent trains with separate supply and return headers. This subsystem configuration provides 100-percent redundancy during normal plant operation and during a LOOP. During normal operation of the subsystem, one pump/chiller train is required to supply chilled water to the components of the nuclear island nonradioactive ventilation system and the radiologically controlled area ventilation system at a normal temperature of 4.4 °C (40 °F). If one train is inoperable, the standby train can be manually aligned to supply chilled water to these components. The design cooling capacity for the low-capacity subsystem is founded on the ambient design temperatures of 46 °C (115 °F) dry bulb and 26.7 °C (80 °F) coincident wet bulb maximum.

The VWS, with the exception of the containment isolation valves, is classified as AP1000 Class D, seismic Category NS. The containment penetration isolation valves are Safety Class B, as is the pipe between the isolation valves.

The VWS has no safety-related function other than containment isolation, and its failure does not affect the ability of safety-related systems to perform their intended safety functions. Therefore, the design conforms to the guidelines of Regulatory Position C.2 of RG 1.29. Regulatory Position C.1 of RG 1.29 does not apply to the VWS because the system performs no safety-related function.

The VWS is not required to achieve safe shutdown or to mitigate any postulated accidents and serves no safety-related function, except for the portion of the system lines routed into the containment that require containment isolation. The high-capacity subsystem supply and return lines that penetrate the containment have two air-operated containment isolation valves. These valves automatically close upon receipt of a containment isolation signal. A bypass mode, with indication in the control room, is also provided to restore containment recirculation system cooling during containment isolation.

Because the VWS has no safety-related function, other than containment isolation, and a failure of the system will not affect the operation of safety-related equipment, the requirements of GDC 44, as related to the capability to transfer heat loads from safety-related systems, GDC 45, as related to inservice inspection of safety-related components and equipment, and GDC 46, as related to operational functional testing of safety-related systems or components, are not applicable.

On the basis of its review, the staff concludes that the safety-related portions of the system (the containment penetrations and the isolation valves) comply with Regulatory Position C.1 of RG 1.29, as they are designed in accordance with containment isolation provisions. Because the system serves no safety-related function and its failure as a result of an SSE would not reduce the functioning of any safety-related plant features, the non-safety-related portion of the system complies with Regulatory Position C.2 of RG 1.29. Therefore, the staff concludes that the design of the VWS meets the guidance of SRP Section 9.2.2 and, therefore, is acceptable.

9.2.8 Turbine Building Closed-Cooling System

The staff reviewed the design of the turbine building closed-cooling system (TCS) in accordance with applicable provisions of SRP Section 9.2.2. With respect to GDC 2, as related to structures and systems being capable of withstanding the effects of earthquakes, acceptance is based on meeting the guidance of Regulatory Position C.2 of RG 1.29 for non-safety-related portions of the system. Because the TCS is not safety-related, the requirements of GDC 4, 44, 45, and 46, as reflected in the guidance of SRP Section 9.2.2 do not apply.

The TCS is a closed-loop cooling water system that provides chemically treated, demineralized water for the removal of heat from non-safety-related heat exchangers in the turbine building and rejects the heat to the circulating water system (CWS). The TCS, which has no safety-related function and is classified as AP1000 Class D, seismic Category NS, consists of two 100-percent capacity pumps, three 50-percent capacity heat exchangers, a surge tank, a chemical addition tank, and associated piping, valves, and instrumentation and controls (I&C).

The TCS complies with GDC 2 by adhering to the guidance of Regulatory Position C.2 of RG 1.29 for ensuring that failures of the TCS during seismic events will not affect the performance of any safety-related systems or components. TCS piping and components are located entirely within the turbine building. No safety-related equipment is located in the turbine building. Therefore, the failure of the TCS (including the effects of jet impingement and flooding) cannot lead to the failure of any safety-related SSCs.

Because the TCS is not safety-related and its failure cannot lead to the failure of any safety systems, the TCS meets the requirements of GDC 2 because it conforms to Regulatory Position C.2 of RG 1.29, as described above. Therefore, the staff concludes that the design of the TCS meets the guidance of SRP Section 9.2.2 and, therefore, is acceptable.

9.2.9 Waste Water System

The staff reviewed the waste water system (WWS) in accordance with SRP Section 9.3.3, "Equipment and Floor Drainage System." Conformance with the acceptance criteria of the SRP forms the basis for concluding that the WWS satisfies the requirements of GDC 2, 4, and 60.

The WWS is a non-safety-related system that collects and processes the waste water from the equipment and floor drains in the nonradioactive building areas during plant operation and outages. Wastes from the turbine building floor and equipment drains are collected in the two turbine building drain tanks for temporary storage. Drainage from the DG building sumps, the auxiliary building nonradioactive sump, and the annex building sump is also collected in the turbine building sumps. The waste water from either of the two drain tanks is then pumped to an oil separator for removal of oily waste. The oil separator has a small reservoir for storage of the separated oily waste which flows by gravity to a waste oil storage tank. The waste oil storage tank provides temporary storage before trucks remove the waste for offsite disposal. The waste water from the oil separator flows by gravity to a waste water retention basin, if required, for settling of suspended solids and treatment before discharge. The effluent in the retention basin is pumped to either the cooling tower basin or to plant outfall, depending on the quality of the water in the waste water retention basin.

If radioactivity is present in the drain tanks, a manual three-way valve allows for the waste water to be diverted from the drain tanks to the liquid radwaste system (WLS) for processing and disposal. A radiation monitor installed on the common discharge piping of the drain tank pumps can detect and isolate the contaminated waste water. The radiation monitor will alarm upon detecting radioactivity in the waste water and trip the drain tank pumps and the waste water retention basin pumps. The applicant states in the DCD that the design includes provisions for sampling the drain tanks for radioactive contamination. Therefore, the staff concludes that the design of the WWS satisfies GDC 60, with respect to control of the release of water from the WWS containing radioactive material.

In DCD Tier 2, Section 9.2.9.5, the applicant indicates that level controls for the building drain tanks and the waste water retention basin will prevent overflow of these waste water collection points. High-water-level alarms will alert the operator to take action. Section 3.4.1.2, "Internal Flooding," of this report discusses the effects of flooding resulting from system pipe breaks or component failures in the nonradiologically controlled areas (NRCAs). The WWS pipe breaks or component failures are not the dominant sources of internal flood in the NRCAs. In Section 3.4.1.2 of this report, the staff concludes that the applicant properly identified safety-related equipment and flood hazards in the NRCAs and provided adequate means of protecting safety-related equipment from the identified flood hazards in the NRCAs. Therefore, the staff concludes that the design of the WWS complies with GDC 4, with respect to flood protection.

The staff also finds that the WWS design complies with the requirements of GDC 2, as related to the ability to withstand the effects of earthquakes. Compliance with GDC 2 is based on meeting the guidance of Regulatory Positions C.1 and C.2 of RG 1.29 concerning seismic classification. The WWS need not comply with Regulatory Position C.1 because the system is not safety-related. Instead, the WWS complies with the guidelines of Regulatory Position C.2 of RG 1.29 because failure of the system during an SSE will not reduce the function of any safety-related plant features.

Based on its review, the staff concludes that the WWS meets the NRC regulations set forth in the following review criteria:

- GDC 2, with respect to protecting the system against natural phenomena
- GDC 4, with respect to preventing flooding that could result in adverse effects on safety-related systems
- GDC 60, with respect to preventing the inadvertent transfer of contaminated fluids to the noncontaminated drainage system for disposal

Therefore, the design of the WWS meets the guidance of SRP Section 9.3.3 and, therefore, is acceptable.

9.2.10 Hot Water Heating System

The hot water heating system (VYS) supplies heated water to selected non-safety AHUs and unit heaters in the plant during cold weather operation and to the containment recirculation fan coil units during plant outages in cold weather. During a loss of normal ac power, onsite DGs will power the system. The VYS has no safety-related function and, therefore, no nuclear safety design basis. The VYS and its associated equipment are classified as AP1000 Class D, seismic Category NS. No GDC or SRP guidelines are directly applicable to the review of the VYS; therefore, the staff based its review of the VYS on relevant regulatory guidance and industry standards.

The VYS is a closed-loop system consisting of a heat transfer package (including two 50-percent capacity heat exchangers, two 50-percent capacity system pumps, a surge tank, and a chemical feed tank) and a distribution system to the various HVAC systems and unit heaters. The VYS is manually actuated and may operate when the site ambient temperature is 23 °C (73 °F) or below. The system uses a steam source from the high-pressure turbine cross-under piping to heat water by transferring the heat energy through the heat exchangers. During a plant outage, the auxiliary steam taken from the auxiliary boiler heats the water. The heated water is pumped to the hot water coils of the various HVAC systems and unit heaters. Condensate from the heat exchanger is level controlled and drained to the main condenser or auxiliary boiler feedwater system. The surge tank maintains the minimum system pressure above the saturation conditions at the pump suction. The chemical feed tank has the capability to provide chemical mixing in the system for corrosion control. The DWS supplies the makeup water for the VYS.

Based on its review and because the VYS is a non-safety-related system, has no safety-related function, and interfaces with only non-safety-related systems, the staff concludes that the requirements of GDC 5, 44, 45, and 46, and Appendix B to 10 CFR Part 50 do not apply to the VYS.

The VYS is a high-energy system. The VYS and VWS share piping inside the containment. During normal plant operation, the VYS is isolated from the VWS and containment. The applicant stated that the VYS piping is generally excluded from safety-related plant areas outside the containment. Piping of this system routed in the safety-related areas is 2.54 cm (1 in.) and smaller and is not evaluated for pipe ruptures.

Section 3.6 of this report addresses the staff's evaluation of the protection against the dynamic effects associated with the postulated rupture of piping.

Section 3.4.1 of this report discusses the staff's evaluation of the effects of flooding caused by postulated rupture of piping on the safe-shutdown capability of the plant.

On the basis of its review, the staff concludes the following:

- The VYS meets the requirements of GDC 2 because it serves no safety-related function and complies with Regulatory Position C.2 of RG 1.29 because it interfaces with only non-safety-related systems and its failure will not affect the functions of the safety-related systems. Regulatory Position C.1 of RG 1.29 is not applicable to the VYS because the system is not safety-related.

- The VYS, as designed to industrial standards as a nonseismic category and classified as AP1000 Class D, is acceptable because it is not a safety-related system.

Therefore, the staff concludes that the design of the VYS is acceptable.

9.3 Process Auxiliaries

The following sections describe the staff's review of the AP1000 process auxiliaries:

- 9.3.1, "Compressed and Instrument Air System"
- 9.3.2, "Plant Gas System"
- 9.3.3, "Primary Sampling System"
- 9.3.4, "Secondary Sampling System"
- 9.3.5, "Equipment and Floor Drainage System"
- 9.3.6, "Chemical and Volume Control System"
- 9.4, "Air Conditioning, Heating, Cooling, and Ventilation System"

9.3.1 Compressed and Instrument Air System

The staff reviewed the compressed and instrument air system (CAS) in accordance with the guidance of SRP Section 9.3.1, "Compressed Air System." Conformance with the acceptance criteria of the SRP forms the basis for concluding whether the instrument air subsystem of the CAS satisfies the following requirements:

- GDC 1, "Quality Standards and Records," as it relates to systems and components being designed, fabricated, and tested to quality standards in accordance with the importance of the safety functions to be performed

- GDC 2, as it relates to the capability of safety-related CAS components to withstand the effects of earthquakes

- GDC 5, as it relates to the capability of shared systems and components to perform required safety functions

Either single-unit or multiple-unit sites can use the AP1000 design. Nonetheless, in DCD Tier 2, Section 3.1.1, the applicant states that the AP1000 design is for a single-unit plant; if more than one unit is built on the same site, multiple units will not share the safety-related systems. If the COL applicant referencing the AP1000 design will be required to apply for the evaluation of the units' compliance with the requirements of GDC 5, "Sharing of Structures, Systems, and Components," with respect to the capability of shared SSCs important to safety to perform their required safety functions.

As identified in DCD Tier 2, Table 3.2-3, the CAS components, with the exception of the containment penetration piping and isolation valves, are classified as non-nuclear-safety-related and nonseismic. The quality assurance requirements of Appendix B to 10 CFR Part 50 do not apply. The containment penetration piping and isolation valves are classified as safety Class 2, seismic Category I, quality group B. DCD Tier 2, Section 9.3.1, Tables 9.3.1-1 to 9.3.1-4, and Figure 9.3.1-1 provide the system description, components, and flow diagrams, respectively.

The CAS consists of the following subsystems:

- the instrument air system
- the service air system

- the high-pressure air system

The CAS has no safety-related function other than containment isolation. The major components of the CAS are located in the turbine building.

Generic Safety Issue (GSI) 43, "Reliability of Air Systems," discusses the safety aspects of air systems in nuclear power plants. Issuance of Generic Letter (GL) 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," resolved GSI 43. The GL requested that licensees and applicants review the recommendations of NUREG-1275, "Operating Experience Feedback Report," and perform a design and operations verification of the system. Section 20.3 of this report provides a complete discussion of how the AP1000 design addresses GSI 43. In DCD Tier 2, Section 9.3.7 Westinghouse states that the COL applicant will address GSI 43 as part of training and procedures identified in DCD Tier 2, Section 13.5. This COL Action Item, as it applies to GSI 43, is discussed in greater detail in Section 20.3 of this report. This is COL Action Item 9.3.1-1.

9.3.1.1 Instrument Air Subsystem

The instrument air subsystem provides high-quality instrument air, as specified in the ANSI/Instrument, Systems, and Automation Society (ISA) S7.3-1981, "Quality Standard for Instrument Air," which is specified in SRP Section 9.3.1. The intake filters for the instrument air subsystem prevent particulates 10 microns and larger from entering the air supply to the compressors.

Sample points are provided downstream of the air dryers in the instrument air subsystem to monitor the air quality supplied by each compressor. Periodic checks ensure high-quality instrument air, as specified in the ANSI/ISA S7.3-1981 standard.

Air-operated valves that are essential for safe shutdown and accident mitigation are designed to actuate to the fail-safe position upon loss of air pressure. DCD Tier 2, Table 9.3.1-1, identifies the safety-related air-operated valves supplied by the instrument air subsystem. There are no safety-related air-operated valves that rely on safety-related air accumulators to actuate to the fail-safe position upon loss of air pressure.

DCD Tier 2, Section 9.3.1.4, states that during the initial plant testing before reactor startup, safety systems utilizing instrument air will be tested to verify fail-safe operation of air-operated valves upon sudden loss of instrument air or gradual reduction of air pressure, as described in RG 1.68.3, "Preoperational Testing of Instrument and Control Air Systems." In addition, DCD Tier 2, Section 14.2.9.4.10, states that testing is performed to verify the fail-safe positioning of safety-related air-operated valves for sudden loss of instrument air or gradual loss of pressure, as described in DCD Tier 2, Section 9.3.1.4.

Therefore, the AP1000 design complies with the guidance of ANSI/ISA-S7.3, as it relates to supplying clean, dry, oil-free air to safety-related components, and the guidance of RG 1.68.3, as it relates to the testing of the CAS. On this basis, the staff concludes that the CAS complies with the requirements of GDC 1, with respect to systems and components important to safety being designed, fabricated, and tested to quality standards commensurate with the importance of the safety functions to be performed.

9.3.1.2 Service Air Subsystem

The service air subsystem is the supply source for plant breathing air. Portable, individually packaged, air purification equipment can be attached to any service air subsystem outlet to improve the service air quality to a minimum of Quality Verification Level D as defined in ANSI/CGA G-7.1. The breathing air purification package consists of replaceable cartridge-type filters, a pressure regulator, carbon monoxide monitoring equipment, air supply hoses, and air supply devices. A catalytic conversion to carbon dioxide within the package controls carbon monoxide. The service air subsystem is not connected to the instrument air subsystem.

9.3.1.3 High-Pressure Air Subsystem

The air compressor of the high-pressure air subsystem has an integral air purification system to produce air for high-pressure applications. This integral high-pressure air purification system utilizes a series of replaceable cartridge-type filters to produce breathing quality air. The high-pressure air subsystem supplies Quality Verification Level E air, as defined in ANSI/CGA G-7.1, and the high-pressure air compressor is checked regularly to verify that the breathing air meets these standards. A catalytic conversion to carbon dioxide within the package controls carbon monoxide. Breathing air connections to the high-pressure air subsystem are incompatible with the breathing air connections of the service air subsystem to prevent attachment of the portable air purification equipment to the high-pressure air subsystem.

The onsite standby DGs provide an alternate source of electrical power for the high-pressure air compressor.

The high-pressure air subsystem is classified as a high-energy system. The high-pressure compressor and receiver are located in the turbine building, which contains no safety-related equipment or structures. Air piping in safety-related areas is 2.54 cm (1 in.) or less in diameter, and an analysis of the dynamic consequences of a rupture is not required. This subsystem is not required to operate following a design-basis accident nor is it used for safe shutdown of the plant.

9.3.1.4 Conclusions

The CAS does not have to comply with Regulatory Position C.1 of RG 1.29 because, with the exception of the inner and outer containment isolation valves and lines in between, the system is non-safety-related. Instead, the CAS complies with Regulatory Position C.2 of RG 1.29 because the CAS is not required to remain functional and its failure as a result of an SSE will not reduce the functioning of any plant feature included in Items 1.A through 1.Q of Regulatory Position C.1 of RG 1.29 to an unacceptable safety level. The SSCs are non-nuclear-safety class, but the structure housing the CAS (turbine building) has a seismic Category II designation. The structure's design and construction ensure that the SSE will not cause any failure that would adversely affect other safety systems, as stated in DCD Tier 2, Section 3.2.1 and Table 3.2-1. Therefore, the system complies with GDC 2, as it relates to the ability of the system to withstand the effects of earthquakes.

On the basis of the preceding review, the staff concludes that the CAS complies with GDC 1, 2, and 5, as referenced in SRP Section 9.3.1 and, therefore, is acceptable.

9.3.2 Plant Gas System

The plant gas system (PGS) provides hydrogen, carbon dioxide, and nitrogen gases to plant systems as required. The PGS does not supply other gases, such as oxygen, methane, acetylene, and argon, which are supplied in smaller individual containers. The hydrogen portion of the PGS supplies hydrogen to the main plant electrical generator for cooling and to other plant auxiliary systems. The carbon dioxide portion stores and supplies carbon dioxide to the generator to purge hydrogen and air during layup or plant outages. The nitrogen portion of the PGS supplies nitrogen for pressurizing, blanketing, and purging various plant components.

The PGS is required for normal plant operation and startup of the plant. The PGS has no safety-related function. Failure of the system does not compromise any safety-related system, nor does it prevent safe reactor shutdown.

The main steam isolation valves (MSIVs) and the main feedwater isolation valves (MFIVs) are safety-related valves that use compressed nitrogen stored within the valve operators as the motive force to close the valves. Note 21 on DCD Tier 2, Figure 10.3.2-1, specifies that the MSIVs and MFIVs are pneumatic-hydraulically actuated with a sealed nitrogen accumulator that provides the stored energy to close the valve. Portable high-pressure nitrogen bottles, which are part of the PGS, provide nitrogen makeup for these valves, if needed, using temporary connections on the valves. Failure of these bottles has no effect on the safety-related function of the MSIVs and MFIVs.

In DCD Tier 2, Section 6.4, "Habitability Systems," the applicant addresses the effect of the PGS on MCR habitability, including explosive gases and burn conditions for those gases. For explosions, the design of the PGS conforms to RG 1.91, "Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants." RG 1.91 provides guidance on acceptable methods to comply with GDC 4, with respect to the dynamic effects of explosions of hazardous materials that may be carried near transportation routes.

The nitrogen and carbon dioxide portions of the PGS are located inside the turbine building, and the hydrogen system storage is located outdoors at the hydrogen storage tank area. DCD Tier 2, Section 3.5, "Missile Protection," contains an analysis of storage tanks as a potential missile source. Section 3.5.1.1 of this report also discusses this scenario.

The staff concludes that the PGS is acceptable because it follows the guidance of RG 1.91.

9.3.3 Primary Sampling System

The staff reviewed DCD Tier 2, Section 9.3.3, "Primary Sampling System," in accordance with SRP Section 9.3.2, "Process and Post-Accident Sampling Systems." The acceptability of the primary sampling system (PSS) is based on whether there are provisions to isolate the system to limit radioactive releases; whether the system meets the intended function of collecting and delivering representative samples of fluids from various plant fluid systems to a laboratory for analysis; and whether it meets the requirements for seismic design and quality group classification described in the following GDC:

- GDC 1, as it relates to the design of the components to standards commensurate with the importance of their safety functions

- GDC 2, as it relates to the design of the components to withstand the effects of natural phenomena

The applicant can meet the requirements of GDC 1 and 2 by following the guidance in RG 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and RG 1.29.

9.3.3.1 <u>Summary of Technical Information</u>

The function of the PSS is to collect liquid and gaseous samples and to provide for local grab samples during normal operation. The system includes provisions to route sample flow to a laboratory for continuous or intermittent sample analysis. The proposed design uses common sampling lines and points. The PSS includes piping, valves, heat exchangers, and other components associated with the system from the point of sample withdrawal from a fluid system up to the analyzing station, sampling station, or local sampling point. The system includes equipment to collect representative samples of various process fluids in a manner that adheres to the ALARA principles during normal and postaccident conditions. In addition, the system design provides a safety-related hydrogen analyzer for monitoring containment atmosphere during a postulated LOCA.

9.3.3.1.1 Process Sampling

During normal plant operations, the PSS collects samples for analysis from the reactor coolant system (RCS), the auxiliary primary process system streams, and the containment atmosphere, as specified in DCD Tier 2, Tables 9.3.3-1 and 9.3.3-2. The results are used to perform the following functions:

- monitor core reactivity
- monitor fuel rod integrity
- evaluate ion exchanger (demineralizer) and filter performance
- specify chemical additions to the various systems
- maintain acceptable hydrogen levels in the RCS
- detect radioactive material leakage

9.3.3.1.2 Postaccident Sampling

The PSS does not have a specific postaccident sampling capability; however, the design of this system allows for collection and analysis of highly radioactive samples of reactor coolant for boron, containment sump for pH, and containment atmosphere for hydrogen and other fission products.

The requirements for the postaccident sampling system are in 10 CFR 50.34(f)(2)(viii). The reactor coolant and containment atmosphere sampling line systems should permit personnel to take a sample under accident conditions promptly and with doses less than 50 milisieverts (5 rem) whole body and 500 milisieverts (50 rem) extremity. The radiological spectrum analysis facilities should be able to promptly quantify certain radionuclides that are indicators of the degree of core damage. In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions.

The NRC published a model safety evaluation report on eliminating the postaccident sampling system requirements from the technical specifications (TS) for operating plants (Volume 65, Number 211, of the Federal Register, dated October 31, 2000). In DCD Tier 2, Section 1.9.3, Item (2)(viii), the applicant states that the AP1000 sampling design basis is consistent with the approach in the model safety evaluation and not with the previous guidance of NUREG-0737, "Clarification of TMI Action Plan Requirements," and RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident." The guidance of the model safety evaluation report discusses contingency plans to obtain and analyze highly radioactive postaccident samples from the RCS, the containment sump, and the containment atmosphere. The applicant states in DCD Tier 2, Section 1.9.3, that the AP1000 design is consistent with the model safety evaluation report guidance. Therefore, the staff finds the applicant's elimination of the postaccident sampling system from the TS for the AP1000 to be acceptable.

9.3.3.2 Staff Evaluation

The intended function of the PSS is to collect and analyze liquid and gaseous samples from the RCS, the auxiliary primary process system streams, and the containment atmosphere. Although the PSS has no safety-related function, some of its sampling lines may connect to safety-related systems. Therefore, to meet the requirements of GDC 1 and 2, the seismic and quality group classification of these lines, associated components, and instruments must conform to the classification of the system to which they are connected. DCD Tier 2, Table 3.2-3, addresses the component classification for the PSS. The PSS components are classified as ASME Class 2 and 3, seismic Category I. This system meets the quality standards in GDC 1 and the seismic requirements of GDC 2 because its design conforms to the classification of the system to which each sampling line and component are connected, in accordance with the regulatory positions in RGs 1.26 and 1.29.

In addition, the PSS provides for system isolation in the event of an accident to limit radioactive releases through containment isolation valves and purging the sample streams back to the system of origin or the appropriate radwaste system. DCD Tier 2, Section 6.2.3, "Containment Isolation System," discusses the isolation function of this system, and Section 6.2.4 of this report evaluates that function. The staff reviewed and evaluated the design of this system and determined that it includes the components to meet the function and operational requirements of the PSS.

9.3.3.3 Conclusions

The staff's review has determined that the design of the PSS is acceptable because it performs the intended function of sampling liquid and gaseous process streams to monitor plant and various system conditions and provides for isolation of the system to limit radiation releases. In addition, by conforming to RGS 1.26 and 1.29, the PSS meets the requirements of GDC 1 and 2.

9.3.4 Secondary Sampling System

The staff reviewed DCD Tier 2, Section 9.3.4, "Secondary Sampling System," in accordance with SRP Section 9.3.2, "Process and Post-Accident Sampling Systems." The secondary sampling system (SSS) is acceptable if it can perform the intended function of collecting and delivering representative samples of fluids from various plant fluid systems to a laboratory for analysis and can satisfy the requirements of GDC 13, "Instrumentation and Control," as they relate to monitoring variables that can affect the fission process, the integrity of the reactor core, and the reactor coolant pressure boundary. Assessment and understanding of integrated secondary plant operations rely on data from this system.

9.3.4.1 Summary of Technical Information

The function of the SSS is to collect and deliver representative samples of fluids from various plant fluid systems to a laboratory for analysis. The SSS relies on continuous in-line analyses for monitoring the secondary chemistry that is required for assessing and understanding integrated secondary plant operations. It samples water from the turbine cycle, demineralized water treatment, and circulated water systems. The SSS can provide information on the following parameters:

- chloride
- sulfate
- silica
- iron
- copper content
- dissolved oxygen
- pH
- conductivity levels

The system offers grab sample capability as a backup method to obtain samples and for use in calibrating the in-line instrumentation. Continuous monitoring of the steam generator (SG) blowdown lines checks for radioactivity caused by primary to secondary tube leaks. In case of high radioactivity, the system automatically isolates this flow path, which prevents introduction of radioactive fluids into the SSS.

9.3.4.2 Staff Evaluation

The staff review has verified that the SSS is capable of collecting and delivering for analysis samples of fluids from secondary systems such as the turbine, demineralized water system, and circulating water system. The system provides a grab sample capability as a backup. These are non-safety-related functions. In addition, the SSS has an isolation capability to prevent leakage of radioactive fluid from the SG boundary. Therefore, the SSS complies with GDC 13, and the staff finds it to be acceptable.

9.3.4.3 Conclusions

The SSS instrumentation is capable of monitoring variables and systems over their anticipated range for normal operation, anticipated operational occurrences, and for accident conditions. This includes both the non-safety-related and the safety-related function of SG isolation. Therefore, the SSS satisfies GDC 13.

9.3.5 Equipment and Floor Drainage System

The staff reviewed the equipment and floor drainage system (EFDS) in accordance with the guidance of SRP Section 9.3.3, "Equipment and Floor Drainage System." Conformance with the acceptance criteria of the SRP forms the basis for concluding whether the EFDS satisfies the following requirements:

- GDC 2, as it relates to the capability of safety-related portions of the system to withstand the effects of earthquakes

- GDC 4, as it relates to the capability of the system to withstand the effects of flooding and the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents

- GDC 60, as it relates to providing a means to suitably control the release of radioactive materials in liquid effluent, including during anticipated operational occurrences

The EFDS consists of the radioactive waste drain system (WRS) and the nonradioactive WWS. These systems collect liquid wastes from equipment and floor drains during normal operation, startup, shutdown, and refueling. The liquid wastes are separated according to the type of waste and are then transferred to appropriate processing and disposal systems. Section 9.2.9 of this report discusses the WWS.

The WRS consists of the following equipment:

- equipment drains
- floor drains
- collection piping
- vents
- traps
- cleanouts
- sampling connections
- valves
- collection sumps
- drain tanks
- sump pumps
- drain tank pumps
- discharge piping

The WRS collects radioactive, borated, chemical, and detergent liquid wastes at atmospheric pressure from equipment and floor drainage of the radioactive portions of the auxiliary building, the annex building, the radwaste building, and the containment building. These radioactive liquid wastes are routed to either the auxiliary building sump, the containment sump, or the reactor coolant drain tank. The contents of the sumps and the drain tank are pumped to the WLS for processing. DCD Tier 2, Sections 9.3.5 and 11.2, Tables 9.3.5-1, 11.2-2, and 11.2-4, and Figures 9.3.5-1, 11.2-1, and 11.2-2, respectively, provide the WRS system description, components, and flow diagrams.

The auxiliary building consists of a radiologically controlled area (RCA) and an NRCA that are physically separated by structural walls and floor slabs, so that flooding in the RCA will not cause flooding in the NRCA. The drain system in the RCA is completely separate from NRCA drains to prevent cross-contamination of nonradioactive areas. There are no permanent connections between the WRS and nonradioactive piping. However, the system provides for temporary diversion of contaminated water from normally nonradioactive drains to the WLS. Section 9.2.9 of this report discusses the detection and diversion of radioactive fluids in the nonradioactive WWS. As discussed above, the WRS is designed to prevent the inadvertent transfer of contaminated fluids to a noncontaminated drainage system for disposal. On the basis of its review, the staff concludes that the WRS complies with the requirements of GDC 60, with respect to preventing the inadvertent transfer of contaminated fluids to a noncontaminated drainage system for disposal.

As identified in DCD Tier 2, Table 3.2-3, the WRS components are classified as non-safety-related, nonseismic, Quality Group D, with the following exceptions:

- containment isolation valves in the discharge line from the containment sump and the reactor coolant drain tank
- backflow preventers in the drain lines from containment cavities to the containment sump
- drain line piping from the backflow preventers to the containment cavities

These are classified as Safety Class 2 or 3, seismic Category I, Quality Group B or C.

DCD Tier 2, Section 9.3.5.1.1, states that the EFDS is designed to prevent damage to safety-related systems, structures, and equipment. Safety-related components are not damaged as a result of EFDS component failure from a seismic event. Single failures of the EFDS and its equipment will not prevent the proper function of any safety-related equipment. Therefore, the staff concludes that the design presented in DCD Tier 2 complies with Regulatory Positions C.1 and C.2 of RG 1.29, and that the WRS complies with the requirements of GDC 2, with respect to the capability to withstand the effects of earthquakes.

Operation of the sump pumps and drain tank pumps is not required to mitigate the consequences of design-basis accidents or flooding events. Section 3.4.1 of this report describes the flood protection aspects of the AP1000. Sump pumps inside the containment are interlocked with the associated containment isolation valves. The pumps trip and the isolation valves close on receipt of containment isolation signals to prevent the uncontrollable release of primary coolant outside the containment. Equipment drains are of adequate size to meet the flow requirements. Sump pumps and drain tank pumps discharge at a flow rate adequate to prevent sump overflow for drain rates anticipated during normal plant operation, maintenance, decontamination, fire suppression system testing, and firefighting activities. Sump and drain tank capacities provide a storage capacity consistent with an operating period of approximately 10 minutes with one pump operating. The design of the drain headers minimizes plugging by making them at least 10.2 cm (4 in.) in diameter, which is large enough to accommodate more than the design flow, and by making the flow path as straight as possible. On the basis of its review, the staff concludes that the WRS complies with the requirements of GDC 4, with respect to the capability to withstand the effects of flooding and the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.

On the basis of the above review, the staff concludes that the WRS complies with GDC 2, 4, and 60, as referenced in Section 9.3.3 of the SRP and, therefore, is acceptable.

9.3.6 Chemical and Volume Control System

The staff reviewed DCD Tier 2, Section 9.3.6, "Chemical and Volume Control System," in accordance with the applicable guidance in SRP Section 9.3.4, "Chemical and Volume Control System (PWR) (Including Boron Recovery System)." The SRP indicates that the CVS is acceptable if it includes components and piping, from the letdown line of the primary system to the charging lines, that provide makeup to the primary system and the reactor coolant pump seal water system. It must also meet the requirements for system performance of necessary functions during normal, abnormal, and accident conditions described in the following GDC:

- GDC 1, as it relates to system components being assigned quality group classifications and application of quality standards in accordance with the importance of the safety function to be performed
- GDC 2, as it relates to structures housing the facility and the system itself being capable of withstanding the effects of earthquakes
- GDC 5, as it relates to shared systems and components important to safety being capable of performing required safety functions
- GDC 14, "Reactor Coolant Pressure Boundary," as it relates to ensuring RCP boundary material integrity by means of the CVS being capable of maintaining RCS water chemistry
- GDC 29, "Protection Against Anticipated Operational Occurrences," as it relates to the reliability of the CVS in providing negative reactivity to the reactor by supplying borated water to the RCS in the event of anticipated operational occurrences.
- GDC 33, "Reactor Coolant Makeup," and GDC 35, "Emergency Core Cooling System," as they relate to the CVS capability to supply reactor coolant makeup in the event of small breaks or leaks in the RCPB, to function as part of the emergency core cooling system (ECCS) assuming a single active failure coincident with the LOOP, and to meet ECCS TSs
- GDC 60 and 61, as they relate to CVS components having provisions for venting and draining through closed systems

9.3.6.1 Summary of Technical Information

The CVS in the AP1000 design consists of regenerative and letdown heat exchangers, demineralizers and filters, makeup pumps, tanks, and associated valves, piping, and instrumentation. In addition, the CVS is a non-safety-related system, and its operation is not required to mitigate design-basis events. DCD Tier 2, Section 9.3.6.1.2, describes the following non-safety-related functions performed by the CVS:

- Purification: The CVS removes radioactive corrosion products, ionic fission products, and fission gases from the RCS to maintain low RCS activity levels.
- Reactor coolant system inventory control and makeup: The CVS provides a means to add and remove mass from the reactor coolant system, as required, to maintain the programmed inventory during normal plant operations.
- Chemical shim and chemical control: The CVS provides the means to vary the boron concentration in the RCS and to control the RCS chemistry for limiting corrosion and enhancing core heat transfer.
- Oxygen control: The CVS maintains the proper conditions in the RCS to minimize corrosion of the fuel and primary surfaces (i.e., adding dissolved hydrogen to eliminate free oxygen and to prevent ammonia formation during power operations and introducing an oxygen scavenger at low RCS temperatures during startup from cold shutdown conditions).
- Filling and pressure testing the RCS: The CVS provides a means for filling and pressure testing the RCS.
- Borated makeup: The CVS provides makeup to the PXS accumulators, core makeup tanks (CMTs), IRWST, and the SFP at various boron concentrations.

The following safety-related functions connected to the CVS are important to reactor safety:

- containment isolation of the CVS lines penetrating containment
- termination of inadvertent RCS boron dilution
- isolation of makeup on a steam generator (SG) or pressurizer high level signal
- preservation of the integrity of the RCS pressure boundary, including isolation of normal CVS letdown from the RCS

9.3.6.2 Staff Evaluation

During an accident, the CVS is not required to provide emergency core cooling or boration. However, the makeup pumps can provide RCS makeup following an accident, such as a small LOCA, and can furnish pressurizer auxiliary spray to reduce RCS pressure in certain accident scenarios, thereby improving the reliability of the plant.

DCD Tier 2, Section 9.3.6.2, "System Description," describes the CVS design, which consists of regenerative and letdown heat exchangers, demineralizers and filters, makeup pumps, tanks, and associated valves, piping, and instrumentation. The CVS purification loop is located entirely inside the containment and operates at RCS pressure in a closed loop without the CVS makeup pumps. It uses the developed head of the reactor coolant pumps (RCPs) as a motive force for the purification flow. The primary coolant passes through the regenerative and letdown heat exchangers, where it is cooled to the temperature compatible with the resin in the demineralizer. The coolant then passes through one of the two demineralizers containing mixed bed resin.

After passing through the demineralizers, the coolant travels through the secondary side of the regenerative heat exchanger back to the primary loop. During plant shutdown, when the pumps are not operating, the RNS provides the motive force for the purification loop.

The CVS has enough capacity to accommodate minor leakage from the RCS and provides inventory control during plant heatups and cooldowns. In addition to controlling coolant inventory in the primary coolant system, the CVS provides borated water for PXS accumulators, CMTs, and the SFP. It is also used for filling and pressure testing of the RCS after maintenance and refueling.

Control of pH is achieved through injecting lithium hydroxide from the chemical mixing tank into the makeup water. Since the CVS is a non-safety-related system, its operation is not required to mitigate design-basis events. Therefore, the CVS does not have to meet the safety-related system requirements. However, the CVS provides the first line of defense during an accident to prevent unnecessary actuation of PXSs.

The staff reviewed the design of the CVS and its ability to maintain the required water inventory and quality in the RCS, provide pressurizer auxiliary spray, control the boron neutron absorber concentration in the RCS, and control the primary water chemistry and reduce coolant radioactivity level. In addition, the staff reviewed the system's ability to provide recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the ECCS in the event of postulated accidents.

The staff also noted the discussion in DCD Tier 2, Section 9.3.6.5, "Design Evaluation," which addresses the basis of the CVS design. DCD Tier 2, Section 3.1, "Conformance with Nuclear Regulatory Commission General Design Criteria," discusses the specific GDC applicable to this system (i.e., GDC 1, 2, 5, 14, 29, 33, 35, 60, and 61). In addition, DCD Tier 2, Section 1.9, "Compliance with Regulatory Criteria," discusses compliance with RGs 1.26 and 1.29.

On the basis of the information provided in those sections of DCD Tier 2, the staff finds that the CVS meets the following:

- GDC 1 and RG 1.26 by assigning quality group classifications to system components in accordance with the importance of the safety function to be performed
- GDC 2 and RG 1.29 by designing safety-related portions of the system to seismic Category I requirements
- GDC 5 by designing AP1000 as a single-unit plant and specifying that additional units on the same site will not share safety-related systems
- GDC 14 by providing the necessary components to maintain reactor coolant purity and material compatibility to reduce corrosion

- GDC 29 by including the necessary components to provide negative reactivity through injection of borated water into the RCS
- GDC 60 and 61 by designing this system to be capable of confining radioactivity by venting and collecting drainage through closed systems

Passive systems satisfy GDC 33 and 35. However, non-safety-related portions of the CVS are designed with the capability to provide borated makeup to the RCS following accidents, such as small LOCAs, SG tube rupture events, and small steamline breaks.

9.3.6.3 Conclusions

DCD Tier 2, Section 9.3.6.5, summarizes the compliance of the CVS with regulatory requirements and guidance. The applicant indicates that it based the design of the CVS on the GDC (1, 2, 5, 14, 29, 33, 35, 60, and 61) and RGs specified in SRP Section 9.3.4. Although the AP1000 CVS is not a safety-related system and its design need not strictly adhere to the criteria listed in the SRP, the applicant compared the AP1000 CVS design to the GDC requirements and concluded that it meets these requirements, which were discussed for the AP1000 in DCD Tier 2, Section 3.1. The staff agrees with this conclusion.

In addition, the staff concludes that the design of the CVS includes the components and piping to provide inventory control and chemically controlled makeup to the primary system. Also, the CVS includes components to isolate containment and preserve the integrity of the reactor coolant pressure boundary (RCPB). Therefore, the staff concludes that because the CVS meets the intent of GDC 1, 2, 5, 14, 29, 33, 35, 60, and 61, it is acceptable.

9.4 Air Conditioning, Heating, Cooling, and Ventilation System

In DCD Tier 2, Section 3.1.1, the applicant states that the AP1000 design is a single-unit plant; if multiple units share the same site, they will not share safety-related systems. Thus, the individual plants will maintain the independence of all safety-related systems and their support systems. The staff determined that the HVAC systems design described in the DCD does not share SSCs with other nuclear power units. Therefore, the HVAC cooling systems meet the requirements of GDC 5. DCD Tier 2, Table 9.4-1, lists the standards to which the various components of the HVAC systems are designed.

The following sections describe the staff's review of the AP1000 air conditioning, heating, cooling, and ventilation systems:

- 9.4.1, "Nuclear Island Nonradioactive Ventilation System"
- 9.4.2, "Annex/Auxiliary Buildings Nonradioactive HVAC System"
- 9.4.3, "Radiologically Controlled Area Ventilation System"
- 9.4.4, "Balance-of-Plant Interfaces"
- 9.4.5, "Engineered Safety Features Ventilation System"
- 9.4.6, "Containment Recirculation Cooling System"
- 9.4.7, "Containment Air Filtration System"
- 9.4.8, "Radwaste Building HVAC System"
- 9.4.9, "Turbine Building Ventilation System"
- 9.4.10, "Diesel Generator Building Heating and Ventilation System"

- 9.4.11, "Health Physics and Hot Machine Shop HVAC System"

Table 9.4-1 of this report lists the relevant codes and standards for the design, maintenance, and testing of air conditioning, heating, cooling, and ventilation systems.

The NRC staff stated, as part of RAI 410.009, that the AP1000 design should comply with the latest revisions of the applicable codes and standards for the following systems:

- radiologically controlled area ventilation system (VAS)
- nuclear island nonradioactive ventilation system (VBS)
- containment recirculating cooling system (VCS)
- main control room emergency habitability system (VES)
- containment air filtration system (VFS)
- health physics and hot machine shop HVAC system (VHS)
- radwaste building HVAC system (VRS)
- turbine building ventilation system (VTS)
- annex/auxiliary buildings nonradioactive HVAC system (VXS)
- DG building heating and ventilation system (VZS)

The RAI also asked that the applicant revise the DCD, as necessary. In a letter dated February 14, 2003, the applicant provided additional information that revised its original response to RAIs 410.007 and 410.009. This response asserts that the AP1000 HVAC design meets the codes and standards and issue date identified in DCD Tier 2, Section 9.4.13, "References," and that these codes and standards are up to date as of the submittal date of the DCD to the NRC. The applicant further assured the staff that the use of these codes and standards will result in a technically suitable HVAC design for the AP1000. The NRC staff expects that a future DCD revision will include the codes and standards (including NRC guidance documents) that are in effect as of the submittal date of DCD Tier 2 (March 28, 2002) and will update the references identified in DCD Tier 2, Sections 6.4.8, 9.4.13, and Appendix 1A. In a letter dated May 21, 2003, the applicant responded to RAI 410.007. Open Item 9.4-1 in the DSER noted that the staff had insufficient time to review this response. The staff reviewed the May 21, 2003, letter and the DCD and determined that the DCD references the latest revisions of the codes and standards relevant to the HVAC systems. Therefore, Open Item 9.4-1 is resolved.

9.4.1 Nuclear Island Nonradioactive Ventilation System

The staff reviewed the VBS in accordance with SRP Section 9.4.1, "Control Room Area Ventilation System." Conformance with the SRP acceptance criteria forms the basis for determining whether the VBS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes

- GDC 4, regarding maintaining environmental conditions in essential areas compatible with the design limits of the essential equipment located in those areas during normal, transient, and accident conditions

- GDC 5, regarding sharing systems and components important to safety

- GDC 19, "Control Room," regarding maintaining the control room in a safe, habitable condition under accident conditions by providing adequate protection against radiation and toxic gases

- GDC 60, regarding the capability to suitably control release of gaseous radioactive effluents to the environment

The VBS provides safety-related, design-basis functions to (1) monitor the air supply for radioactive particulate and iodine concentrations inside the main control room envelope (MCRE), and (2) isolate the safety-related, seismic Category I HVAC piping penetrating the MCRE based on the detection of "high-high" particulate or iodine radioactivity in the supplied air or on the extended loss of ac power supporting operation of the main control room (MCR) emergency habitability system as described in Section 6.4 of this report. The system is designed to maintain proper environmental conditions and control of contaminant levels. The VBS maintains the MCR and technical support center (TSC) carbon dioxide levels below 0.5-percent concentration and keeps the air quality within the guidelines of Table 1 and Appendix C, Table C-1, to the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 62-1999, "Ventilation for Acceptable Indoor Air Quality." The applicant states that the VBS is non-safety-related; however, if the system is operational and ac power is available, the system provides for habitability inside the MCRE (within the guidelines of SRP Section 6.4, "Control Room Habitability System") and the TSC (within the guidelines of NUREG-0696, "Functional Criteria for Emergency Response Facilities"). However, since the VBS is non-safety-related, there is no basis for the staff to assume that it will be operable during a design basis accident.

The VBS can provide habitability because its design, construction, and testing conform to GSI B-36, "Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Features Systems and for Normal Ventilation Systems"; GSI B-66, "Control Room Infiltration Measurements"; RG 1.140, Revision 2, "Design, Inspection and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," as discussed in DCD Tier 2, Chapter 1.0, Appendix 1A, and ASME N-510-1989, "Testing of Nuclear Air Cleaning Systems." Chapter 20 of this report discusses GSI B-36.

In addition, the applicant state in DCD Tier 2, Section 9.4.12, "Combined License Information," that COL applicants referencing the AP1000 design will implement a program to maintain compliance with ASME/ANSI AG-1-1997, "Code on Nuclear Air and Gas Treatment," and Addenda AG-1a-2000, "Housings"; ASME N-509-1989, "Nuclear Power Plant Air-Cleaning Units and Components"; ASME N-510-1989; and RG 1.140, Revision 2, for portions of the VBS and VFS identified in DCD Tier 2, Sections 9.4.1 and 9.4.7. The staff finds this acceptable because the applicant referred to industry codes and standards that are specified in RG 1.140, Revision 2. This is COL Action Item 9.4.1-1.

For the post-72-hour design-basis accident, the specific function of the VBS is to maintain the MCR below a temperature approximately 2.5 °C (4.5 °F) above the average outdoor temperature. In addition, the VBS is designed to maintain the instrumentation and control (I&C) rooms (Divisions B and C) below the qualification temperature of the I&C equipment (49 °C or 120 °F) for the post-72-hour design-basis accident. The ancillary fans are intended to meet the above post-72-hour ventilation criteria for the MCR and Class 1E I&C rooms. Section 8.3 of this report discusses the staff's evaluation of the post-72-hour power supply.

The VBS consists of the following subsystems:

- The MCR/TSC HVAC subsystem serves the MCR and the TSC.
- The Class 1E electrical room HVAC subsystem serves the Class 1E dc equipment rooms, electrical penetration rooms, battery rooms, and I&C rooms, remote shutdown area, reactor cooling pump trip switchgear rooms, and adjacent corridors.
- The PCS valve room heating and ventilating subsystem serves the PCS valve room.

Descriptions, design parameters, instrumentation (including indications and alarms), and figures for the VBS and the interfacing VES appear in DCD Tier 2, Sections 6.4, 9.4.1, and 15.6.5.3; Tables 3.2-1, 6.4-1 through 6.4-3, 9.4.1-1, and 15.6.5-2; and Figures 1.2-8, 6.4-1, 6.4-2, and 9.4.1-1. DCD Tier 2, Section 7.3, "Engineered Safety Features," discusses instrumentation for the VES and VBS. DCD Tier 2, Section 11.5, "Radiation Monitoring," gives details of radiation monitors, including testing and inspection. Section 9.2.7 of this report discusses the staff's evaluation of the chilled water system, and Section 9.5.1 discusses the staff's evaluation of fire protection. Table 9.4-1 of this report describes the industry standards applicable to the HVAC system, including components of the VBS.

The MCRE penetrations include isolation valves, interconnecting piping, and vent and test connections with manual valves that are classified as safety Class C and seismic Category I. The MCRE isolation valves have electrohydraulic operators and are designed to fail closed during a LOOP event. The TS for periodic testing and the inservice testing (IST) program include the safety-related isolation valves.

The design, construction, and testing of the MCR/TSC HVAC subsystem filtration unit configurations, including housing, internal components, ductwork, dampers, fans and controls, and the location of the fans on the filtered side of units, are in accordance with ASME N-509-1989, ASME N-510-1989, and RG 1.140, Revision 2. The ductwork for the supplemental air filtration subsystem and portions of the MCR/TSC HVAC subsystem that maintains the integrity of the MCR/TSC pressure boundary, during conditions of abnormal airborne radioactivity, is tested for leak tightness in accordance with ASME 510-1989.

The remaining supply and return/exhaust ductwork is tested in place for leakage in accordance with the 1985 Sheet Metal and Air-Conditioning Contractor's National Association (SMACNA), "HVAC Duct Leakage Test Manual." The high-efficiency particulate air (HEPA) filters are shop tested to verify an efficiency of at least 99.97 percent using a monodisperse 0.3-μm aerosol and constructed, qualified, and tested in accordance with ASME N-509-1989 and the 1996 Underwriters Laboratory (UL)-586, "High-Efficiency, Particular, Air-Filter Units." Postfilters downstream of the charcoal adsorbers have a minimum dioctyl-phthalate polydispersed (DOP) test efficiency of 95 percent. Each charcoal adsorber is a single assembly with welded construction and 100-mm (4-in.)-deep type III rechargeable adsorber cell. The charcoal adsorbers conform with NRC Inspection and Enforcement (IE) Bulletin 80-03, "Loss of Charcoal from Adsorber Cells," and are qualified, constructed, and tested in accordance with ASME/ANSI AG-1-1997 and Addenda AG-1a-2000, ASME N-509-1989, ASME N-510-1989, and RG 1.140, Revision 2. Laboratory tests must verify that a representative charcoal sample, used or new, has a minimum charcoal efficiency of 90 percent in accordance with RG 1.140, Revision 2, and test procedures and test frequency must conform with ASME N-510-1989.

The system ductwork flow is tested, balanced, and adjusted in accordance with SMACNA-1993, "HVAC Systems Testing, Adjusting, and Balancing." Fire dampers or combination fire/smoke dampers are provided at duct penetrations through fire barriers to maintain the fire-resistance ratings of the barriers. The MCR/TSC HVAC and Class 1E electrical room HVAC subsystems are designed so that smoke, hot gases, and fire suppressant do not migrate from one fire area to another to the extent that they could adversely affect safe-shutdown capabilities, including operator actions. The MCRE areas, Class 1E equipment rooms, and the remote shutdown workstation room have fire or combination fire and smoke dampers to isolate each fire area from adjacent fire areas during and following a fire, in accordance with the National Fire Protection Association (NFPA) 90A, "Installation of Air Conditioning and Ventilation Systems."

If the VBS is not available during the 72-hour period following the onset of a postulated design-basis accident, the VES provides passive heat sinks to limit the temperature rise in the MCRE, I&C rooms, and dc equipment rooms. The heat sinks consist primarily of the thermal mass of the concrete that makes up the ceilings and walls of these rooms. As described in DCD Tier 2, Section 6.4.2.2, a metal form is attached to the surface of the concrete at selected locations to enhance the heat-absorbing capacity of the ceilings. Metallic plates are attached perpendicularly to the ceiling metal form. These plates extend into the room and act as thermal fins to enhance the heat transfer from the room air to the concrete. The VBS cooling and heating capacity depends on the site interface parameters for maximum and minimum normal temperature conditions, as defined in DCD Tier 2, Table 2-1, as summarized in the following:

- The MCR/TSC HVAC subsystem maintains the MCR and TSC between 19.4 and 23.9 °C (67 to 75 °F) and 25 percent to 60 percent relative humidity. The VBS maintains the VES passive cooling heat sink below its initial design ambient air temperature limit of 23.9 °C (75 °F).

- The Class 1E electrical room HVAC subsystem maintains the Class 1E dc equipment rooms between 19.4 and 23.9 °C (67 to 75 °F); Class 1E electrical penetration rooms, Class 1E battery rooms, Class 1E instrumentation and control rooms, remote shutdown area, reactor cooling pump trip switchgear rooms, and adjacent corridors between 19.4 and 22.8 °C (67 to 73 °F); and HVAC equipment rooms between 10 to 29.4 °C (50 and 85 °F).

- The VBS maintains the Class 1E electrical room emergency passive cooling heat sink below its initial design ambient air temperature limit of 23.9 °C (75 °F).

- The VBS vents the Class 1 battery rooms to limit the hydrogen gas concentration to less than 2 percent by volume.

- The PCS valve room heating and ventilation subsystem maintains the PCS valve room at 10 to 48.9 °C (50 to 120 °F).

The single outside air intake serving the VBS conforms with the guidance of Section 6.4 of the SRP and RG 1.78, Revision 1, "Evaluating the Habitability of a Nuclear Power Plant Control

Room During a Postulated Hazardous Chemical Release." The MCR/TSC HVAC subsystem provides outside supply air to the plant through an outside air intake that is protected by an intake enclosure located on the roof of the auxiliary building at Elevation 153'-0". As stated in DCD Tier 2, Section 6.4.4, the fresh air intake of the MCR is located in excess of 45.7 m (150 ft) from the flue gas exhaust stacks of the onsite standby power DGs, and 91.4 m (300 ft) from the onsite standby power system fuel oil storage tanks. This distance precludes the combustion fumes or smoke from an oil fire from being drawn into the MCR. The fresh air intake is located more than 15.2 m (50 ft) below and more than 30.5 m (100 ft) laterally away from the plant vent discharge. The split-wing-type tornado protection dampers close automatically and can withstand the effects of 134 m/s (300 mph) wind.

As shown in DCD Tier 2, Figure 9.4.1-1, a fail-closed, electrohydraulically operated isolation damper at the inlet of each air filtration train can automatically isolate the fresh air supply from an air intake. Normally, one VBS air filtration unit train isolation damper is open, and the other air filtration unit train isolation damper is closed. There are two fail-closed isolation dampers in series in the common outside air supply to each of the normal air handling units. DCD Tier 2, Figure 9.4.1-1, shows the radiation monitors and outside air isolation dampers. Redundant smoke monitors at the outside air intake continuously monitor the outside air. Redundant safety-related radiation monitors are located in the MCRE upstream of the supply air isolation valves. As described in DCD Tier 2, Section 9.4.1.2.3.1, these monitors initiate operation of the non-safety-related supplemental air filtration units when there are "high" gaseous radioactivity concentrations and they isolate the MCR from the VBS when "high-high" particulate or iodine radioactivity concentrations occur.

In DCD Tier 2, Section 9.4.12, the applicant states that the COL applicant will describe the MCR/TSC HVAC subsystem's recirculation mode during emergencies involving toxic substances, and explain how the subsystem equipment isolates and operates, as applicable, consistent with the issues regarding toxic substances that the COL applicant will address, as discussed in DCD Tier 2, Section 6.4.7. This is COL Action Item 6.4-3, as discussed in Section 6.4 of this report.

Portions of the VBS that provide the defense-in-depth (DID) function of filtration of MCR/TSC air during conditions of abnormal airborne radioactivity are designed, constructed, and tested to conform with GSIs B-36 and B-66, RG 1.140, and ASME N-509 and N-510 standards. The MCR/TSC HVAC subsystem has system redundancy, and it is automatically transferred to the onsite non-safety-related DGs if a LOOP occurs. The VBS is located in the auxiliary building with its equipment in separate fire areas and high enough in the building for protection from flooding. DCD Tier 2, Chapters 17, 16, and 13, address system quality assurance, availability, and administrative controls. The equipment procured will meet manufacturer's standards, and like the other equipment of the nuclear island, it will have protection from defined natural phenomena.

The plant control system controls the VBS, except for the MCRE isolation valves, which are controlled by the protection and safety monitoring system. Chapter 7 of this report discusses the plant control and plant safety and monitoring systems. For the DID VBS supplemental air filtration units, DCD Tier 2, Section 9.4.1.5, discusses the instrumentation to satisfy Table 4-2 of ASME N-509-1989. Radioactivity indication and alarms inform the MCR operators of gaseous, particulate, and iodine radioactivity concentrations in the MCR supply air duct. In DCD Tier 2, Section 11.5, the applicant describes the MCR supply air duct radiation monitors and their actuation functions. Smoke monitors are provided to detect smoke in the outside air intake duct to the MCR and the MCR and Class 1E electrical room return air ducts. Temperature indications and alarms are provided in the return air ducts control the room air temperatures within the predetermined range. Temperature indications and alarms for the MCR return air, Class 1E electrical return room air, AHU supply air, supplemental filtration unit prefilter inlet air, and charcoal adsorbers are provided to inform plant operators of abnormal temperature conditions. Pressure differential indications and alarms are provided to control the MCR and monitor the TSC ambient pressure differentials with respect to the surrounding areas. Airflow indication and alarms are provided to monitor operation of the supply and exhaust fans.

9.4.1.1 Main Control Room/Technical Support Center HVAC Subsystem

As shown in DCD Tier 2, Figure 6.4-1, the MCR/TSC subsystem serves the MCRE which consists of the main control area, shift supervisor office, tagging room, toilet (area), clerk room, kitchen/operator area, hallway, and double door vestibule. The MCR/TSC subsystem also serves the TSC, consisting of the main TSC operating area, conference rooms, NRC room, computer rooms, shift turnover room, kitchen/rest area, and restrooms. The MCR and TSC toilets each have a separate exhaust fan.

The MCR/TSC subsystem consists of redundant 100-percent capacity supply AHUs, supplemental air filtration units, return/exhaust air fans, associated dampers, I&C, and common ducts for the MCR and TSC. Each supply AHU consists of a mixing box section, supply air fan, a low-efficiency filter bank, a high-efficiency filter bank, an electric heating coil, chilled water cooling coil bank, and a humidifier. Air-cooled chillers in the VWS normally supply the chilled water.

The supply AHUs and return/exhaust air fans connect to a common duct that distributes air to the MCR/TSC HVAC subsystem. The only HVAC penetrations in the MCRE are MCR supply, return, and toilet exhaust ducts. These penetrations include redundant, safety-related seismic Category I isolation valves that are physically located in the MCRE. The isolation valves isolate the non-safety-related portions of the subsystem from the MCRE when the VES is operating.

The normal outside makeup air enters the subsystem through an outside air intake duct protected by a nonseismic Category I intake enclosure. The applicant states that the nonseismic Category I enclosure is acceptable because failure of the VBS air intake enclosure will not affect the safety-related operation of the VES, including the initial pressure assumptions required by the VES to maintain control room habitability during a design-basis LOCA. The A and C Class 1E electrical room HVAC subsystem shares the outside supply air intake enclosure for the MCR/TSC HVAC subsystem. The staff agrees with the applicant's justification for a nonseismic Category I intake enclosure.

Temperature sensors located in the MCR return air duct control the tempered air through each AHU to maintain the ambient air design temperature within its normal design temperature range by modulating electric heating or chilled water cooling coil.

Each supplemental air filtration unit includes a high-efficiency filter bank, an electric heating coil, a charcoal adsorber with an upstream and downstream HEPA filter bank, and a fan. Both redundant trains of the supplemental filtration units and one train of the supply AHU are located in the MCR mechanical equipment room at Elevation 135'-3" of the auxiliary building. The other supply AHU is located in the MCR mechanical equipment room at Elevation 135'-3" of the annex building. The MCR toilet exhaust fan is located at Elevation 135'-3" of the auxiliary building. The filtration unit's housings, located outside the MCRE, are designed to meet the performance requirements of ASME/ANSI AG-1-1997 and Addenda AG-1a-2000, ASME N-509 and N-510 standards. They operate at a negative pressure.

In DCD Tier 2, Table 9.4.1-1, the applicant showed that the depth of the activated charcoal adsorber is 102 mm (4 in.), with an adsorber efficiency of 90 percent and a HEPA filter efficiency of 99 percent. In addition, DCD Tier 2, Table 9.4.1-1 shows a maximum MCRE in-leakage of 177 standard cubic meters per hour (scmh) (110 standard cubic feet per minute (scfm)) [including in-leakages of 16 scmh (10 scfm) through MCR access doors, 16 scmh (10 scfm) through TSC access doors, and 145 scmh (90 scfm) through MCR/TSC HVAC equipment and ductwork (operating)]. In a revision to the DCD, the applicant stated that the testing for MCR/TSC in-leakage during MCR/TSC HVAC subsytem operation will be conducted in accordance with ASTM E741, 2000. The staff finds the applicant's commitment acceptable for the VBS testing for these in-leakages. The MCR/TSC HVAC equipment ductwork, which forms an extension of the MCR/TSC pressure boundary, limits the overall infiltration (negative operating pressure) and exfiltration (positive operating pressure) rates to those values shown in DCD Tier 2, Table 9.4.1-1, to maintain operator doses within the allowable GDC 19 limits, as applied to the AP1000 design.

During normal operation, one of the two 100-percent capacity supply AHUs and supply/exhaust air fans operate continuously. Outside makeup air to supply AHUs enters through an air intake duct. The outside airflow rate is automatically controlled to maintain the MCR/TSC areas at a slightly positive pressure with respect to the surrounding areas and outside environment. The standby AHU and its corresponding return/exhaust fans start automatically if (1) the operating fan airflow drops below predetermined setpoints, (2) return air temperature rises above or drops below predetermined setpoints, (3) differential pressure between the MCR and the surrounding areas and outside environment is above or below predetermined setpoints, or (4) the operating unit loses electrical and/or control power.

The applicant described the design and operation of the MCR/TSC HVAC subsystem in DCD Tier 2, Section 9.4.1.2.3.1. During abnormal plant operation with high gaseous radioactivity detected in the MCR supply air duct, the system is designed to maintain control room operator doses within the dose acceptance criteria of GDC 19, as applied to the AP1000 design. When monitors detect high gaseous radioactivity in the MCR supply air duct and the MCR/TSC HVAC subsystem is operable, both supplemental air filtration units automatically start to pressurize the MCR/TSC areas to at least 0.03 kPa (1/8" water gauge) using filtered makeup. Operators then manually shut down one of the supplemental filtration units. The normal outside air makeup duct and the MCR and TSC toilet exhaust duct isolation valves close. If open, the smoke/purge isolation dampers close. The subsystem AHU continues to provide cooling, in the recirculation mode, by maintaining the MCRE passive heat sink below its initial ambient air design temperature and maintaining the MCR/TSC areas within their design temperature. The supplemental filtration pressurizes the combined volume of the MCR and TSC concurrently with filtered air. A portion of the recirculated air (approximately 1.89 m^3/sec (4000 cfm)) from the MCR and TSC is also filtered for cleanup of airborne radioactivity.

During abnormal operation, if ac power is unavailable for more than 10 minutes or "high-high" particulate or iodine radioactivity is detected in the MCR supply air duct (which would lead to operator dose limits in excess of the requirements of GDC 19, as applied to the AP1000 design), the plant safety monitoring system automatically isolates the MCRE from the normal MCR/TSC HVAC subsystem by closing the supply, return, and toilet exhaust isolation valves. The VES safety-related supply isolation valve in each train opens automatically to protect the MCR occupants from a potential radiation release, because the radiation monitors are effective only when air is flowing through the VBS ductwork. Section 6.4 of this report discusses the emergency mode of operation.

The staff performed independent radiological consequence analyses for personnel in the MCR and TSC following all AP1000 design basis accidents. This was to verify Westinghouse's assertion that, with ac power available, the VBS can maintain control room and TSC doses within 0.05 Sv (5 rem) TEDE. Staff's review of the applicant's analysis of control room habitability and the staff's independent confirmatory radiological consequence analyses for the control room operators are discussed in Chapter 15.3 of this report. The staff finds that the system design, as bounded by the control room atmospheric relative concentrations proposed by Westinghouse, is capable of controlling radioactivity following design basis accidents to maintain dose to personnel in the MCR and TSC within 0.05 Sv (5 rem) TEDE, when ac power is available for the duration of the accident.

The VBS is not designed as a post-accident engineered safety-feature atmospheric cleanup system and has no safety grade source of power. Therefore, it was not credited in evaluating conformance with GDC 19 as applied to the AP1000 main control room design. Chapter 6.4 of this report includes the staff's evaluation of the MCR emergency habitability system (VES) and AP1000 conformance to GDC 19.

The MCR/TSC subsystem complies with GDC 60, as it relates to protecting those who access the control room during accidental radioactive releases, by initiating the supplemental filtration subsystem. The MCR/TSC subsystem conforms with RG 1.140, Revision 2, regarding detection of high radioactivity or isolating the MCRE and initiating the VES when the redundant nuclear safety-related radiation monitors detect "high-high" airborne radioactivity. The ventilation supply and return/exhaust air ducts in the MCR and TSC areas can be manually isolated from the MCR.

An alarm in the MCR warns if a high concentration of smoke is detected in the outside air intake. The MCR/TSC subsystem is then manually realigned to the recirculation mode by closing the outside air and toilet exhaust duct isolation dampers. The MCR and TSC toilet/kitchen exhaust fans are tripped when the isolation valves close. During the recirculation mode, the MCR/TSC areas are not pressurized. The MCR/TSC subsystem continues to provide cooling and ventilation to maintain the emergency passive heat sink below its initial ambient air design temperature and the MCR/TSC areas within their design temperature.

In the event of a fire in the MCR/TSC, the fire/smoke dampers close automatically to isolate the fire area, while the MCR/TSC subsystem maintains the unaffected areas at a slight positive pressure. The MCR/TSC subsystem continues to provide ventilation and cooling to the unaffected areas to maintain them at a slight positive pressure. The MCR/TSC subsystem can be realigned manually to the once-through ventilation mode to supply 100-percent outside air to the unaffected areas.

The plant ac electrical system supplies power to the subsystem. In the event of a LOOP when the plant ac electrical system is unavailable, the subsystem is automatically transferred to the onsite standby DGs.

In the event that complete ac power is lost and the outside air is acceptable (on the basis of compliance with the requirements of GDC 19), one of the two MCR ancillary fans operate to supply outside air to the MCRE and thus maintain MCRE habitability. DCD Tier 2, Section 9.4.1.2.3.1, describes the outside air supply pathways to the ancillary fans and warm air vent pathways. Power to the ancillary fans is from the respective Division B or C regulating transformers, which receive power from the ancillary DGs. The ancillary fans' flow paths are located within the auxiliary building, which is a seismic Category I structure. Once normal ventilation is restored, the ancillary fan circuits are disabled manually. The applicant states that the ancillary fans are of the centrifugal type with nonoverloading horsepower characteristics; the fans conform to ANSI/AMCA 210, 211, and 300 standards; and each fan can provide a minimum of 0.722 m^3/sec (1530 cfm). The capacity and airflow rate maintain the MCRE environment near the daily average outdoor air temperature. As discussed in Section 22.5.7 of this report, short-term administrative controls for the MCR ancillary fans are part of the regulatory treatment of non-safety systems (RTNSS) process.

9.4.1.2 <u>Class 1E Electrical Room HVAC Subsystem</u>

The Class 1E electrical room (ER) HVAC subsystem has two ventilation trains. One train serves the A and C electrical divisions, spare battery rooms (non-Class 1E), Class 1E spare battery rooms, and reactor pump trip switchgear rooms; the other train serves the B and D electrical divisions and the remote shutdown workstation area.

Each subsystem consists of two 100-percent capacity AHUs, return/smoke exhaust air fans, associated dampers, I&C, and common ductwork. The AHUs and return/exhaust fans connect to a common duct that distributes supply air to the Class 1E electrical rooms. Each supply AHU consists of a mixing box section, supply air fan, a low-efficiency filter bank, a high-efficiency filter bank, an electric heating coil, and chilled water cooling coil bank. Air-cooled chillers in the VWS normally supply the chilled water. In addition, the Class 1E battery rooms have duct-mounted electric heating coils and two 100-percent capacity exhaust fans. The HVAC equipment serving the A and C electrical divisions is located in the MCR A and C equipment rooms at Elevation 135'-3" of the auxiliary building. The HVAC equipment serving the B and D electrical divisions is located in the upper and lower B and D equipment rooms at Elevation 117'-0" and Elevation 135'-3" of the auxiliary building.

During normal operation, one of the redundant supply AHUs, return fans, and battery room exhaust fans operates continuously to maintain acceptable environmental conditions, maintain the Class 1E electrical room emergency passive heat sink below its initial ambient air temperature, and prevent hydrogen gas buildup in the Class 1E battery rooms. The battery exhaust is vented directly to the turbine building vent to limit the hydrogen gas concentration to less than 2 percent by volume, in accordance with RG 1.128, Revision 1, "Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants."

The normal outside makeup air enters the subsystem through an outside air intake duct protected by an intake enclosure. The A and C Class 1E ER HVAC subsystem and the MCR/TSC HVAC subsystem share a common outside supply air intake, located on the roof of the auxiliary building at Elevation 153'-0". The outside supply air intake for the B and D Class 1E ER HVAC subsystem is located separately from the MCR/TSC HVAC subsystem air intake enclosure on the roof of the auxiliary building at Elevation 153'-0".

Temperature sensors located in the return air duct control the tempered air through each AHU. The tempered air maintains the room air temperature within the normal design range by modulating electric heating or the chilled water cooling coil. The standby supply AHU, and corresponding return/smoke exhaust fans, start automatically if the operating fan airflow drops below a predetermined set point, the return air temperature rises above or drops below predetermined setpoints, or the operating unit loses electrical and/or control power.

Abnormal events resulting in detectable airborne radioactivity in the MCR supply air duct of the MCR/TSC HVAC subsystem do not affect the operation of the Class 1E ER HVAC subsystem. During a design-basis accident (DBA), if both onsite and offsite power are lost, the Class 1E ER emergency passive heat sink will provide area temperature control, as discussed in Section 6.4 of this report.

An alarm in the MCR warns if a high concentration of smoke is detected in the air intake. The Class 1E ER HVAC subsystem is then manually realigned to the recirculation mode of operation by closing the outside air intake damper to the AHU mixing plenum, allowing 100-percent room air to return to the supply air subsystem AHU. During the recirculation mode of operation, the subsystem continues to maintain the served areas within their design temperatures and pressures.

In the event of a fire in a Class 1E ER, fire/smoke dampers close automatically to isolate the fire area, and the ER HVAC system maintains the unaffected areas at a slight positive pressure. One or both trains of the subsystem can be manually realigned to the once-through ventilation mode to provide 100-percent outside air to the unaffected areas.

Realignment to the once-through ventilation mode minimizes the potential for migration of smoke and hot gases from a non-Class 1E ER (or a non-Class 1E ER of one division into the Class 1E ER of another division). Reopening the closed combination fire/smoke dampers from outside of the affected fire area during the once-through ventilation mode can remove smoke and hot gases from the affected areas. In the once-through ventilation mode, the outside air intake damper (to the AHU mixing plenum) opens and the return air damper (to the supply AHU) closes to allow 100-percent outside air to the supply AHU. The subsystem exhaust air isolation damper also opens to exhaust room air directly to the turbine building vent.

The plant ac electrical system supplies power to the subsystem. If a LOOP occurs and the plant's ac electrical system is unavailable, the subsystem is automatically transferred to the onsite standby DGs.

When complete ac power is lost, Division B and C MCR ancillary fans operate to supply outside air to the I&C rooms and maintain I&C room temperature. DCD Tier 2, Section 9.4.1.2.3.2, describes the outside air supply pathways to the ancillary fans and warm air vent pathways. Division B or C regulating transformers, which receive power from the ancillary DGs, supply power to the ancillary fans. The ancillary fans' flow path is located within the auxiliary building, which is a seismic Category I structure. Once normal ventilation is restored, the ancillary fan circuits are disabled manually. As discussed in Section 22.5.7 of this report, short-term administrative controls for the MCR ancillary fans are part of the RTNSS process.

9.4.1.3 Passive Containment Cooling System Valve Room Heating and Ventilating Subsystem

The PCS valve room heating and ventilation subsystem consists of one 100-percent capacity exhaust fan, two 100-percent capacity electric unit heaters, and associated dampers, instrumentation, and controls. The subsystem equipment is located in the PCS valve room in the containment dome area at Elevation 286'-6".

During normal operation, the exhaust fan draws outside air through an intake louver damper and directly exhausts it to the environment to maintain room temperature within its normal design temperature range. The lead electric unit heater starts or stops when the room air temperature rises above or drops below predetermined setpoints. The standby electric unit heater starts automatically if the airflow temperature of the operating electric unit heater drops below a predetermined setpoint.

The plant ac electrical system powers the exhaust fan and electric heaters. In the event of a LOOP, the power source is automatically transferred to the onsite standby DGs for the electric unit heaters. Following a fire in the PCS valve room, portable exhaust fans and flexible ductwork can remove smoke and hot gases from the area.

9.4.1.4 Conclusions

The VBS is located inside seismic Category I (auxiliary building) and seismic Category II (annex building) structures, which provide flood and tornado-missile protection. The safety-related MCR isolation dampers are seismic Category I, as shown in DCD Tier 2, Table 3.2-1. Therefore, the system's safety-related portions comply with the guidelines of Regulatory Position C.1 of RG 1.29. The system's non-safety-related portions comply with Regulatory Position C.2 of RG 1.29 because the tornado damper installed at the outside air intake and the MCR fire dampers meet seismic Category II requirements, so that the failure of system components during an SSE will not reduce the functioning of any safety-related plant features. System equipment and ductwork located in the nuclear island, the failure of which could affect the operability of safety-related systems or components, are designed to seismic Category II requirements. The remaining portions of the system are nonseismic. Therefore, the system complies with GDC 2 requirements, as they relate to protection of the system against natural phenomena.

Redundant safety-related components of the MCR/TSC HVAC subsystem are physically separated and are protected from internally-generated missiles, pipe breaks, and water spray. All safety-related components are seismic Category I and designed to function following an SSE. The system maintains its function even with the loss of any single active component. In Sections 3.4.1, 3.5.1.1, 3.5.2, and 3.6.1 of this report, the staff documents its evaluation of the design to protect against floods, internally and externally-generated missiles, and high- and moderate-energy pipe breaks. On the basis that the MCR/TSC HVAC subsystem is designed to accommodate and be compatible with environmental conditions and consider dynamic effects, the staff concludes that the control room habitability systems satisfy GDC 4, as it relates to protecting the system against floods, internally-generated missiles, and piping failures.

As stated in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VBS meets the requirements of GDC 5.

COL applicants referencing the AP1000 design will identify the toxic gases to be monitored. Section 6.4 of this report discusses the specifics relating to compliance with GDC 19, as it pertains to protection of the control room against intrusion of toxic gases. As stated in that section, the COL applicant can demonstrate compliance with GDC 19 in this regard by complying with the guidance of RG 1.78, Revision 1. Since the guidance of RG 1.78, Revision 1, is site dependent, compliance is the responsibility of the COL applicant. Section 6.4 of this report also discusses compliance with GDC 19, as it relates to radiation dose limits for the control room operator.

The VBS is a nonradioactive HVAC system that serves areas where no radioactive sources are anticipated. Therefore, GDC 60 is not applicable.

As a result of the RTNSS process, short-term administrative controls apply to the MCR ancillary fans that provide long-term cooling to the MCR and I&C rooms in the event of a total loss of ac power.

On the basis of this review, the staff concludes that the VBS complies with GDC 2, 4, 5, 19, and 60, as referenced in Section 9.4.1 of the SRP, and consequently with the subject SRP acceptance criteria.

9.4.2 Annex/Auxiliary Buildings Nonradioactive HVAC System

The staff reviewed the VXS in accordance with the SRP Section 9.4.3, "Auxiliary and Radwaste Area Ventilation System." Conformance with the SRP acceptance criteria forms the basis for concluding whether the VXS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes
- GDC 5, regarding sharing systems and components important to safety
- GDC 60, regarding the capability of the system to suitably control release of gaseous radioactive effluents to the environment

The VXS is a nonradioactive HVAC system that serves the nonradioactive personnel and equipment areas; the electrical equipment rooms, clean corridors, ancillary DG room, and demineralized water deoxygenating room in the annex building; and the MSIV compartments, reactor trip switchgear rooms, and piping and electrical penetration areas in the auxiliary building.

Because the VXS is not required to support any functions or operation of any equipment or systems listed in Regulatory Position C.1 of RG 1.29, this guideline is not applicable to the VXS. Additionally, the portions of the VXS located in areas containing safety-related components will be seismically supported in accordance with Regulatory Position C.2 of RG 1.29. Therefore, the VXS conforms with GDC 2, "Design-Basis Protection Against Natural Phenomena."

DCD Tier 2, Section 9.4.2, Tables 9.4.2-1 through 9.4.2-7, and Figure 9.4.2-1, respectively, provide the system description, design parameters, and piping and instrumentation drawings (P&IDs). In DCD Tier 2, Table 3.2-3, the applicant provides the classification of the VXS system and components. Table 9.4-1 of this report describes the industry standards applicable to the components of the VXS. The VXS supply airflow is balanced in accordance with the guidelines of SMACNA-1983, "HVAC Systems—Testing, Adjusting, and Balancing."

The VXS is designed to maintain proper operating temperatures in the following areas on the basis of the site interface parameters for maximum and minimum normal temperature conditions defined in DCD Tier 2, Table 2-1. The following summarizes these values:

- for the annex building:
  - offices, corridors, locker rooms, toilet rooms, central alarm stations, and security areas between 22.8 °C to 25.6 °C (73 °F to 78 °F)
  - non-Class 1E battery rooms between 15.6 °C to 32.2 °C (60 °F to 90 °F)
  - switchgear and battery charger rooms, HVAC and mechanical equipment room, and ancillary DG room between 10 °C to 40.6 °C (50 °F to 105 °F)
  - switchgear rooms, battery charger rooms, and ancillary DG room during upset conditions (LOOP), with DGs operating, maximum temperature of 50 °C (122 °F)
- for the auxiliary building:
  - MSIV compartments, non-safety electrical penetration rooms, reactor trip switchgear rooms, and valve/piping penetration room between 10 °C to 40.6 °C (50 °F to 105 °F)
  - demineralized water deoxygenating room, elevator machine room, and boric acid batching room between 10 °C to 40.6 °C (50 °F to 105 °F)

The VXS protects against the buildup of hydrogen concentrations to less than 2 percent in the non-Class 1E battery rooms in the annex building.

DCD Tier 2, Section 7.3, describes the VXS instrumentation. The plant control system (PLS) controls the VXS. The temperature controllers maintain the proper air temperatures and provide indication and alarms that are accessible locally via the PLS. Temperature is indicated for each AHU supply air discharge duct, except for local recirculation units such as those in the MSIV compartments and valve/piping penetration room.

The VXS has the following six independent subsystems, as shown on DCD Tier 2, Figure 9.4.2-1:

- general area HVAC subsystem
- switchgear HVAC subsystem
- equipment room HVAC subsystem

- MSIV compartment heating and cooling subsystem
- mechanical equipment areas HVAC subsystem
- valve and piping penetration room HVAC subsystems

The following sections discuss these subsystems.

9.4.2.1 General Area HVAC Subsystem

The general area HVAC subsystem serves personnel areas in the annex building outside the security area, which include the men's and women's change rooms, shower/toilet areas, the ALARA briefing room, and operational support center, offices, and corridors. The subsystem is not credited for plant abnormal conditions.

This subsystem consists of two 50-percent capacity supply AHUs (8200 scmh each (5100 scfm each)), a humidifier, a ducted supply and return air system, diffusers and registers, and exhaust fans, as well as associated dampers, instrumentation, and controls. The subsystem AHUs are located on the low roof of the annex building at Elevation 117'-6". During normal operation, both AHUs and the toilet/shower exhaust fan operate continuously to keep the served areas within the design temperature range.

Each AHU of the general area HVAC subsystem consists of a centrifugal supply air fan, low-efficiency filter bank, high-efficiency filter bank, a hot water heating coil with integral face/bypass damper, and a chilled water cooling coil. The units discharge into a ducted supply distribution system, which is routed through the building to provide air to the various rooms and areas served via registers. Temperature controllers, with their sensors located in the annex building main entrance, control the AHUs. The temperature controllers modulate the chilled water control valves and the face and bypass dampers of the hot water heating coil in the AHUs and automatically control the switchover between cooling and heating modes. The VWS provides chilled water, and the VYS provides hot water. Outdoor makeup air is added at the AHU to replace air exhausted from the toilet and shower facilities in the annex building. A common steam humidifier is located in the ductwork downstream of the AHUs to provide a minimum space RH of 35 percent; the humidistat control is located in the main entrance of the annex building. The men's and women's locker rooms and the toilet and shower facilities in the annex building have an exhaust fan that exhausts directly to the outside environment.

An electric heating coil tempers the supply air inside the men's and women's facilities. A temperature controller, with a sensor located in the women's facility, controls the heating coil elements.

During replacement of the AHU filters, the affected supply fan is stopped, and subsystem isolation dampers isolate it from the duct system. The toilet/shower exhaust fan is also stopped. During filter replacement mode, the subsystem runs at 50-percent capacity and maintains the served areas in the annex building at a slight positive pressure.

9.4.2.2 Switchgear HVAC Subsystem

This subsystem serves the electrical switchgear rooms in the annex building. The subsystem consists of two 100-percent capacity AHUs, a ducted supply and return air system, and automatic controls and accessories. During normal plant operation, one AHU operates continuously to keep the served areas within the design temperature. The AHU has a temperature controller to maintain the tempered air supply at 16.7 °C (62 °F) dependent on the outdoor ambient temperature conditions.

Each subsystem AHU consists of a centrifugal return/exhaust fan, return/exhaust air plenum, low-efficiency filter bank, high-efficiency filter bank, a hot water heating coil with integral face and bypass dampers, a chilled water cooling coil, and centrifugal supply fan. The AHUs discharge into a common duct supply distribution system, which is routed through the building to the various areas served. The air then returns to the AHU. The VWS and VYS provide chilled and hot water, respectively. The AHUs are located in the north air handling equipment room in the annex building at Elevation 135'-3". The AHUs connect to a common plenum (which also supplies the outdoor air to the equipment room HVAC subsystem) located along the east wall adjacent to the air handling equipment room.

When the outdoor air temperature is above 16.7 °C (62 °F), the outdoor air, return air, and exhaust air dampers automatically reposition to provide minimum outdoor air, and the temperature controller modulates the chilled water control valves to maintain the supply air at 16.7 °C (62 °F). When the outside air temperature is below 16.7 °C (62 °F), each temperature controller modulates the outdoor air, return air, and exhaust air dampers to control a mixture of the return and minimum outdoor air in the proper proportion and modulates the face and bypass dampers of the hot water heating coils to maintain a mixed air temperature of 16.7 °C (62 °F).

During replacement of the AHU filters, the affected supply fan is stopped, and subsystem isolation filters isolate the affected AHU from the duct system. During filter replacement mode, the second AHU of the subsystem runs at full system capacity.

In its once-through smoke exhaust ventilation mode, this subsystem can remove smoke after a fire. Additionally, the alternate subsystem, which consists of 100-percent capacity supply and exhaust propeller fans (mounted in the annex building wall) and controls, provides cooling to electrical switchgear rooms 1 and 2 if the primary subsystem AHUs are unavailable because of a fire. The switchgear rooms will be kept at or below 50 °C (122 °F). The operator will control the fans to keep the area above freezing.

In the event of a LOOP, the supply and return/exhaust fans are connected to the standby power system to provide the DID cooling function to the diesel bus switchgear. In this mode, outdoor air and return air volume dampers are positioned to the once-through flow mode to maintain the switchgear rooms at or below 50 °C (122 °F), where equipment is designed for continuous operation under this environment. To maintain the areas above freezing, the mixing dampers will modulate to maintain a supply air temperature of 16.7 °C (62 °F) for outdoor temperatures below 16.7 °C (62 °F). For outdoor temperatures above 16.7 °C (62 °F), the outdoor air, return air, and exhaust air dampers are positioned for a once-through flow.

9.4.2.3 <u>Equipment Room HVAC Subsystem</u>

This subsystem serves the electrical and mechanical equipment rooms in the annex and auxiliary buildings. These rooms include non-Class 1E battery charger rooms 1 and 2, non-Class 1E battery rooms 1 and 2, non-Class 1E penetration room on Elevation 100'-0" and non-Class 1E penetration room on Elevation 117'-6", and reactor trip switch gear rooms 1 and

2. This system also serves the security area offices and central alarm stations in the annex building (including restrooms, access areas, and corridors).

This subsystem consists of two 100-percent capacity AHUs, two battery room exhaust fans, a toilet exhaust fan, a ducted supply and return air system, and automatic controls and accessories. During normal plant operation, one AHU operates continuously to keep the served areas within the design temperature. The AHU has a temperature controller to maintain the tempered air supply at 16.7 °C (62 °F). Each subsystem AHU consists of a centrifugal return/exhaust fan, return/exhaust air plenum, low-efficiency filter bank, high-efficiency filter bank, a hot water heating coil with integral face and bypass, a chilled water cooling coil, and centrifugal supply fan.

The AHUs discharge into a common duct supply distribution system, which is routed through the building to the various areas served. The air is then returned to the AHU, except for the battery rooms and restrooms. The VWS and VYS provide chilled and hot water, respectively. The AHUs are located in the north air handling equipment room in the annex building at Elevation 135'-3". They connect to a common plenum, which also supplies the outdoor air to the switchgear room HVAC subsystem, located along the east wall adjacent to the air handling equipment room.

When the outdoor air temperature is above 16.7 °C (62 °F), the outdoor air, return air, and exhaust air dampers automatically reposition to provide minimum outdoor air, and the temperature controller modulates the chilled water control valves to maintain the supply air at 16.7 °C (62 °F). When the outside air temperature is below 16.7 °C (62 °F), each temperature controller modulates the outdoor air, return air, and exhaust air dampers to control a mixture of the return and minimum outdoor air in the proper proportion. The face and bypass dampers of the hot water heating coils are also modulated to maintain a mixed air temperature of 16.7 °C (62 °F).

The electrical reheat coils are installed in the ductwork of non-Class 1E battery rooms, security area offices, and central alarm stations. The hot water unit heaters are in the north air handling equipment room and operate intermittently to keep the area above 10 °C (50 °F). A steam humidifier installed in the security areas ductwork provides a minimum RH of 35 percent.

A temperature controller opens the outdoor intake for the elevator machine room and starts and stops the elevator machine room exhaust fan, as required, to maintain the elevator machine room at design temperature conditions. A local thermostat controls the electric unit heater in the elevator machine room.

Each non-Class 1E battery room exhaust system consists of an exhaust fan, gravity backdraft damper, and associated ductwork located in the fan discharge, and exhausts to the atmosphere to prevent a hydrogen gas buildup above 2 percent. Air supplied to the battery rooms by the AHUs is exhausted to the atmosphere. A separate exhaust fan exhausts air from the restroom to the atmosphere.

During replacement of the AHU filters, the affected supply fan is stopped, and subsystem isolation dampers isolate the affected AHU from the duct system. During filter replacement mode, the second AHU of the subsystem runs at full system capacity.

Auxiliary Systems

The portion of the subsystem servicing the auxiliary building is designed so that smoke, hot gases, and fire suppressant will not migrate from one fire area to another, to the extent that they could adversely affect safe-shutdown capabilities, including operator actions. Fire dampers or combination fire and smoke dampers, which close in response to smoke detector signals or in response to the heat from a fire, isolate each fire area from adjacent fire areas during and following a fire, in accordance with NFPA 90A requirements.

In the event of a LOOP, the supply and return/exhaust fans are connected to the standby power system to provide the DID cooling function to the dc switchgear and inverters. In this mode, outdoor air and return air volume dampers are positioned for the once-through flow mode to keep the dc switchgear and inverter areas at or below 50 °C (122 °F). The equipment is designed for continuous operation under this environment. To maintain the areas above freezing, the mixing dampers will modulate to maintain a supply air temperature of 16.7 °C (62 °F) for outdoor temperature below 16.7 °C (62 °F). For outdoor temperatures above 16.7 °C (62 °F), the outdoor air, return air, and exhaust air dampers are positioned for a once-through flow.

9.4.2.4 Main Steam Isolation Valve HVAC Subsystem

The MSIV HVAC subsystem serves the two MSIV compartments in the auxiliary building that contain the main steam and feedwater piping. The main steam and feedwater lines between the turbine building and containment are routed through two separate compartments in the auxiliary building. This subsystem is not credited for plant abnormal conditions.

The MSIV HVAC subsystem consists of two 100-percent capacity AHUs in each compartment (5300 scmh each (3300 scfm each)), supply and air distribution ducting, and automatic controls and accessories. During normal plant operation, one of the AHUs in each compartment operates continuously in a recirculation mode to maintain the design temperature range in the area served by the system.

Each AHU consists of a low-efficiency filter bank, a hot water heating coil, a chilled water cooling coil, a centrifugal supply air fan, and associated I&C. The VWS and VYS provide chilled and hot water, respectively. Each compartment has two inside air temperature indicators. The air temperature controller automatically handles the switchover between cooling and heating modes.

A temperature controller that modulates the chilled water and hot water control valves serving each unit maintains the temperature of the MSIV compartment at or less than 40.6 °C (105 °F) and above a minimum of 10 °C (50 °F). For investment protection, the standby power system can power the subsystem in the event of a LOOP.

The AHU may be shut down for replacement while another AHU in the same MSIV compartment operates to keep the served area within the design temperature range. The AHUs can be connected to the standby power system during a LOOP event for investment protection.

9.4.2.5 Mechanical Equipment Areas HVAC Subsystem

The mechanical equipment areas HVAC subsystem serves the ancillary DG room, the demineralized deoxygenating room, boric acid batching room, and upper and lower south air handling equipment rooms in the auxiliary building. This subsystem maintains the served areas at a slightly positive pressure with respect to the adjacent buildings by supplying a constant volume of outside air. This subsystem is not credited for plant abnormal conditions.

The mechanical equipment areas HVAC subsystem consists of two 50-percent capacity AHUs with supply fans and return/exhaust fans (3538 scmh each (2200 scfm each)), a ducted supply and return air system, and automatic controls and accessories. During normal plant operation, the AHUs operate continuously to maintain the served areas within design temperature range. During replacement of the AHU filters, the affected AHU is stopped, and subsystem isolation dampers isolate it from the duct system. During filter replacement mode, the subsystem operates at approximately 50-percent capacity.

Each subsystem AHU consists of a return/exhaust fan, return/exhaust air plenum, low-efficiency filter bank, high-efficiency filter bank, hot water heating coil with integral face/bypass damper, chilled water cooling coil, centrifugal fan, and associated I&C. The VWS and VYS provide chilled and hot water, respectively. The AHUs are located in the lower south air handling equipment room on Elevation 135'-3" of the annex building. The outdoor air enters from the nontornado-missile-protected air intake plenum #2, which also serves the VAS, VHS, and VFS, and is located at the extreme south end of the annex building between Elevations 135'-3" and 158'-0".

The air temperature indicators are inside the lower south air handling equipment room. Temperature controllers with sensors located in the upper south air handling equipment room maintain the temperature of the area. The temperature controllers modulate the chilled water control valves, and the face and bypass dampers of the hot water heating coil in the AHUs, to keep the areas served by the subsystem within the design temperature range. The area temperature controller automatically controls the switchover between cooling and heating modes.

This subsystem also serves the ancillary DG room and maintains it within the design temperature range when the ancillary DGs are not in operation. A separate exhaust fan dispels the air in the DG room to the outdoors. The exhaust fan for the ancillary DG room operates continuously for room ventilation. The AHUs supply air to the ancillary DG room to maintain normal temperatures. Manually operating dampers and opening room doors to allow radiator discharge air to be exhausted directly to the outside provide ventilation and cooling for the ancillary DGs.

9.4.2.6 Valve and Piping Penetration Room HVAC Subsystem

The valve and piping penetration room HVAC subsystem consists of local recirculation HVAC units to cool the valve/piping penetration room located at Elevation 100'-0" of the auxiliary building. The subsystem is not credited for plant abnormal conditions.

The valve/piping penetration room HVAC subsystem consists of two 100-percent capacity AHUs and has an automatic ducted supply (2894 scmh each (1800 scfm each)) and return air system, as well as automatic controls and accessories. The AHUs are located directly within the space served on Elevation 100'-0". During normal operation, one AHU operates continuously in a recirculation mode to maintain the served area within the design temperature range.

Each AHU in the subsystem consists of a low-efficiency filter, a hot water heating coil, a chilled water cooling coil, centrifugal supply air fan, and associated I&C. The VWS provides chilled water, and the VYS provides hot. Two inside air temperature indicators are provided for each valve and piping penetration room HVAC subsystem. The area temperature controller automatically handles the switchover between cooling and heating modes.

The temperature controllers, with sensors located in the room, modulate the chilled water control valves and the hot water control valves in the operating AHU to maintain the temperature of the valve/piping penetration room at or less than 40.6 °C (105 °F) and above a minimum of 10 °C (50 °F).

Local thermostats control the hot water and electric unit heaters. The area temperature indication is accessible from the MCR. The pressure indication and high differential pressure alarm are provided for each of the filters in the AHUs for filter replacement. The operational status of fans is indicated in the MCR, and the automatic dampers have position-indicating lights. The airflow is indicated for the discharge ducts of the AHUs, and the fan discharge ducts have alarms for low flow rates. The discharge ducts of the AHUs have smoke alarms.

9.4.2.7 Conclusions

Because the VXS is non-safety-related, Regulatory Position C.1 of RG 1.29 does not apply. Additionally, the portions of the VXS located in areas containing safety-related components will be seismically supported in accordance with Regulatory Position C.2 of RG 1.29. System equipment and ductwork located in the nuclear island, the failure of which could affect the operability of safety-related systems or components, are designed to seismic Category II requirements. The remaining portions of the system are nonseismic. Therefore, the VXS conforms to the requirements of GDC 2.

As stated in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VXS meets the requirements of GDC 5.

The VXS is a nonradioactive HVAC system that serves areas where no radioactive sources are anticipated. Therefore, GDC 60 is not applicable.

The staff evaluated the VXS for conformance with GDC 2, 5, and 60, as referenced in Section 9.4.3 of the SRP, and concludes that the design of the VXS is acceptable.

9.4.3 Radiologically Controlled Area Ventilation System

The staff reviewed the VAS in accordance with SRP Sections 9.4.2, "Spent Fuel Pool Area Ventilation System," and 9.4.3, "Auxiliary and Radwaste Area Ventilation System." Conformance with the SRP acceptance criteria forms the basis for concluding whether the VAS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes
- GDC 5, regarding sharing systems and components important to safety
- GDC 60, regarding the capability of the system to suitably control release of gaseous radioactive effluents to the environment
- GDC 61, regarding the capability of the system to provide appropriate containment, confinement, and filtering to limit releases of airborne radioactivity to the environment from the fuel storage facility under normal and postulated accident conditions

The VAS neither serves nor supports the plant safety-related functions; therefore, the system has no nuclear safety design basis. The VAS consists of the following two subsystems:

- the auxiliary/annex building ventilation subsystem (AABVS)
- the fuel-handling area ventilation subsystem (FHAVS)

The VAS serves the fuel-handling area of the auxiliary building and the radiologically controlled portions of the auxiliary and annex buildings. The VAS maintains environmental conditions appropriate for equipment operation, for performing maintenance and testing, and for allowing personnel access. The VAS ventilation airflow rate dilutes potential airborne contamination to within the effluent concentration limits allowed by 10 CFR Part 20 at the site boundary during normal plant operation. The plant's internal airborne concentration levels will be within the 10 CFR Part 20 occupational derived air concentration limits.

The VAS maintains normal airflow direction from lower to higher potential airborne concentrations for ALARA considerations. The design of the VAS exhaust subsystems conforms with the requirements of Appendix I to 10 CFR Part 50 for releases during normal operation. Upon detection of high airborne radioactivity in the air exhaust duct or high ambient pressure differential (resulting from an imbalance in supply and exhaust airflow rates), the system isolates unfiltered normal VAS exhaust. In addition, the VFS filtered exhaust subsystem starts to filter the exhaust air from the fuel-handling area (as well as the auxiliary and annex buildings) to minimize unfiltered offsite releases. These areas are maintained at a slight negative pressure with respect to the adjacent clean areas when high airborne radioactivity is detected. The VFS mitigates exfiltration of unfiltered airborne radioactivity by maintaining the isolated zone at a slightly negative pressure with respect to the outside environment and adjacent unaffected plant areas. The VFS maintains a slightly negative pressure differential with respect to the outside environment until operation of the auxiliary/annex building ventilation subsystem (AABVS) and fuel-handling area ventilation subsystem (FHAVS) is restored.

The configuration of the AABVS supply and exhaust ducts results in two independently isolatable building zones. A radiation monitor is located in the exhaust duct, upstream of an isolation damper, in each zone served by the AABVS. The FHAVS supply and exhaust ductwork is arranged to exhaust the SFP plume and to provide directional airflow from the rail car bay/filter storage area into the spent fuel resin equipment rooms. The FHAVS contains a radiation monitor that is mounted upstream of an isolation damper in the exhaust duct. Unfiltered, but monitored, exhaust from the AABVS and the FHAVS is routed to the plant vent during normal operation. However, if high radioactivity is detected, the subsystems' exhaust is filtered through the VFS and then routed to the plant vent. Section 11.5 of this report discusses the staff's review of radiation monitoring. In conjunction with the VFS as described above, the VAS provides appropriate containment, confinement, and filtering to limit releases of airborne radioactivity to the environment from the fuel storage facility during normal and postulated accident (non-DBA) conditions, in accordance with GDC 61. However, these features receive no credit in the determination of the radiological consequences of a fuel-handling accident (FHA). Chapter 15 of this report discusses the radiological consequences of an FHA.

Each radwaste effluent holdup tank exhaust connects to the AABVS exhaust ducting to prevent the potential buildup of airborne radioactivity or hydrogen gas that may leak within the tanks. The exhaust is then routed to the plant vent through the VFS. The AABVS provides sufficient ventilation to the gaseous radwaste equipment areas to dilute hydrogen gas that may leak from the radwaste equipment into the equipment rooms. The hydrogen gas concentration is kept below a safe level (of about 1 percent) which conforms with the guidelines of SRP Section 11.3. DCD Tier 2, Table 11.3-2 describes the hydrogen monitoring instrumentation. Section 11.3 of this report provides an evaluation of the gaseous waste management system.

DCD Tier 2, Section 9.4.3, Tables 3.2-3 and 9.4.3-1, and Figure 9.4.3-1, respectively, give the VAS description, component design parameters, and piping and instrumentation drawings (P&IDs). Table 9.4-1 of this report describes the industry standards applicable to the components of the VAS. The VAS supply airflow is balanced in accordance with the guidelines of SMACNA-1993, "HVAC Systems—Testing, Adjusting, and Balancing."

The VAS is a once-through design that draws outdoor air and exhausts the air to the plant vent. During normal plant operation, VAS supply AHUs and exhaust fans for both the AABVS and FHAVS operate continuously to ventilate the areas on a once-through basis. The VAS AHUs automatically shut down if airflow or supply air temperature is below a predetermined setpoint. Temperature controllers maintain proper supply air temperature to maintain the ambient room temperature within the normal range. Temperature sensors in the supply air duct control the temperature of the air supplied by each AHU of the AABVS and FHAVS. When the outdoor air temperature is low, the face and bypass dampers across the supply air heating coil are modulated to maintain the ambient room temperature. When the outdoor air temperature is high, the chilled water coil tempers the supply air. The VWS provides chilled water for the VAS and the VYS supplies hot.

The VAS cooling and heating capacity depends on the site interface parameters for maximum and minimum normal temperature conditions, as defined in DCD Tier 2, Table 2-1. The annex building staging areas and storage areas, as well as other corridors and staging areas, are maintained between 10 °C and 40 °C (50 °F and 104 °F). The corridors and access areas served by the FHAVS are maintained between 10 °C and 40 °C (50 °F and 104 °F). The AABVS serves the radiation chemistry laboratory and security rooms and maintains them between 22.8 °C and 25.6 °C (73 °F and 78 °F). The AABVS also serves the primary sample room and maintains it between 10 °C and 40 °C (50 °F and 104 °F).

DCD Tier 2, Section 7.3, describes the VAS instrumentation. The PLS controls the VAS. The temperature controllers maintain the proper air temperatures and provide indications and alarms. The pressure differential indications and alarms monitor the outside air and inside ambient pressures of the fuel-handling area and auxiliary/annex buildings and control the supply airflow to maintain a slightly negative pressure differential with respect to adjacent clean areas and outdoors. Operators can view the area temperature indication from the MCR for the

RNS and makeup pump rooms without accessing these rooms. Auxiliary building and fuel-handling area radiation monitoring instrumentation (radiation detectors) is in the system exhaust ducts upstream of the isolation dampers. As described above, upon detection of high airborne radioactivity in the air exhaust duct or high ambient pressure differential, the unfiltered exhaust air ducts are automatically isolated and the VFS filtered exhaust automatically starts. The MCR is provided with indication and alarms in the exhaust ducts from the fuel-handling area and radiologically controlled areas of the auxiliary and annex buildings. Operational status of fans and dampers is indicated in the MCR. All fans and AHUs can be operated or shut down from the MCR. The system filters and unit coolers have pressure indications and high differential pressure alarms.

During normal operation, smoke monitors located downstream of the AHUs and upstream of the exhaust fans continuously monitor the AABVS and FHAVS ventilation air. The supply AHUs automatically shut down if monitors detect an airflow rate of the fans or air temperature below a predetermined set point.

During abnormal plant operation, if smoke is detected in the supply or exhaust ducts, an alarm is initiated in the MCR. HVAC subsystems remain in operation, but MCR operators may shut down manually if necessary. In the event of a fire within the served areas, local fire dampers automatically isolate the HVAC ductwork penetrating the affected fire area once the local temperature exceeds the predetermined setpoints.

9.4.3.1 <u>Auxiliary/Annex Building Ventilation Subsystem</u>

The configuration of the AABVS supply and exhaust ducts comprise two zones. One zone serves the annex building staging and storage area, containment air filtration rooms, containment access corridor, and adjacent auxiliary building staging area, equipment areas, middle annulus, middle annulus access room, and security rooms. The other zone includes the remaining rooms and corridors shown in Figure 9.4.3-1, sheet 2 of 3, including but not limited to the radiation chemistry laboratory, primary sample room, SFP cooling water pump and heat exchanger rooms, RNS pump and heat exchanger rooms, CVS makeup pump room, lower annulus, and various radwaste equipment rooms, pipe chases, and access corridors. The AABVS provides conditioned air to maintain the following proper operating temperatures in the following areas:

- the residual heat removal and CVSs' pump rooms (pumps not operating), containment purge exhaust filter rooms (fans not operating), liquid radwaste pump rooms, HVAC equipment room, gaseous equipment rooms, and SFP pump and heat exchanger rooms, between 10 °C and 40 °C (50 °F and 104 °F)

- the degasifier column, RNS and CVS pump rooms (pumps operating), containment purge exhaust filter rooms (fans operating), and liquid radwaste tank rooms between 10 °C and 54.4 °C (50 °F and 130 °F)

The supply air flow rate is modulated to maintain a slightly negative pressure differential with respect to the outside environment. The annex building heating coil provides supplementary heating for the exterior annex/auxiliary building areas. The AABVS consists of two 50-percent capacity supply AHUs (28,944 scmh each (18,000 scfm each)), two 50-percent capacity exhaust fans sized to allow the AABVS to maintain a negative pressure in served areas with respect to the adjacent areas, associated ductwork, dampers, diffusers and registers, and I&C. Each AHU consists of a centrifugal supply air fan, a low-efficiency filter bank, a high-efficiency filter bank, a water heating coil with integral face and bypass dampers, a chilled water cooling coil, and associated I&C. The supply AHUs are located in the south air handling equipment room of the annex building at Elevation 158'-0" and are connected to common air intake plenum #3. The common, nontornado-missile-protected air intake plenum #3 is located at the extreme south end of the annex building between Elevation 158'-0" and about 180'-0". Each subsystem AHU discharges into a ducted supply distribution system, which is routed through the radiologically controlled areas of the auxiliary and annex buildings.

The AABVS exhaust fans are located in the auxiliary building at Elevation 145'-9". The supply and exhaust ducts have isolation dampers. During normal operation, the subsystem's exhaust is unfiltered and directed to the plant vent for discharge. During high-radiation isolation mode, the normal unfiltered ventilation subsystem is isolated from the affected zone when high airborne radioactivity is detected, and the isolated area is exhausted through the VFS to the monitored plant vent. The VFS exhaust fans prevent unfiltered airborne releases by maintaining these areas at a slight negative pressure with respect to the outside environment and adjacent clean plant areas.

Each CVS makeup and normal RNS pump room has a dedicated, 100-percent capacity unit cooler (for a total of two per CVS and RNS pump room) to provide supplemental cooling during pump operation. Redundant trains of the VWS supply chilled water to the coolers. Each unit cooler consists of a low-efficiency filter bank, a cooling coil bank, and a fan; each RNS pump room cooler alsohas redundant cooling coil banks. Therefore, either redundant train of the VWS can support the operation of both RNS pumps simultaneously. The CVS pump room coolers are connected to redundant trains of the VWS; however, either train unit cooler can maintain the common makeup pump room temperature conditions and support either makeup pump operation. The pump room coolers automatically start whenever the associated pump receives a start signal or a high room temperature signal. In a LOOP event, the onsite DGs can power unit coolers.

A concrete floor section and flexible seals that connect the containment steel shell to the shield building separate the upper annulus from the middle annulus area of the auxiliary building. The annulus seal provides a passive ventilation barrier during normal operation or during isolation of the auxiliary building to prevent the exfiltration of unmonitored releases from the middle annulus to the environment.

Locally installed electric coils and humidifiers supplement the supply air ducts in the radiation chemistry laboratory and security room to maintain environmental conditions comfortable for personnel. The electric unit heaters provide supplemental heating in the middle annulus as shown in DCD Tier 2, Figure 9.4.3-1.

9.4.3.2 Fuel-Handling Area Ventilation Subsystem

The FHAVS serves the fuel-handling area, rail car bay/filter storage area, resin transfer pump/valve room, spent resin tank room, waste disposal container area, solid radwaste system (WSS) (spent resin) valve/piping area, and elevator machine room.

The FHAVS provides air to maintain the following temperatures:

- the rail car bay/filter storage area between 10 °C and 40 °C (50 °F and 104 °F)
- the spent resin equipment rooms between 10 °C and 54.4 °C (50 °F and 130 °F)
- the fuel-handling area between 10 °C and 35.6 °C (50 °F and 96 °F)
- the areas occupied by plant personnel during refueling activities, to a maximum wet bulb temperature of 26.7 °C (80 °F), within the guidelines of Electric Power Research Institute NP-4453

The supply airflow is modulated to maintain the served areas at a slight negative pressure differential with respect to the outside environment. The rail car bay heating coil provides supplementary heating for the rail car bay. The FHAVS consists of two 50-percent capacity supply AHUs (15,276 scmh each (9500 scfm each)), two 50-percent capacity exhaust fans sized to allow the FHAVS to maintain a negative pressure in served areas with respect to the adjacent areas, associated ductwork, dampers, and I&C. Each AHU consists of a centrifugal supply air fan, a low-efficiency filter bank, a high-efficiency filter bank, a water heating coil with integral face and bypass damper, a chilled water cooling coil, and associated I&C. These areas form a single isolation zone when high airborne radioactivity is detected in the exhaust air. The supply AHUs are located in the south air handling equipment room of the annex building at Elevation 135'-3" and connect to common air intake plenum #2. The common, nontornado-missile-protected air intake plenum #2 is located at the south end of the annex building between Elevation 135'-3" and about 158'-0". Each subsystem AHU discharges into a ducted supply distribution system, which is routed to the fuel-handling area and rail car bay/filter storage areas of the auxiliary building.

The FHAVS supply AHUs are located in the south air handling equipment room of the annex building at Elevation 135'-3", and the exhaust fans are located in the upper radiologically controlled area ventilation system equipment room at Elevation 145'-9" of the auxiliary building. The exhaust has isolation dampers. During normal operation, the subsystem's exhaust is unfiltered and goes to the plant vent for discharge and monitoring of offsite gaseous releases. In high-radiation isolation mode, the normal unfiltered ventilation subsystem is isolated from the affected zone, and the isolated area is exhausted through the VFS to the monitored plant vent.

9.4.3.3 Conclusions

As described in DCD Tier 2, Section 9.4.3 and Table 3.2-3, the VAS is located completely within a seismic Category I auxiliary building and seismic Category II annex building structures, and all system components are non-safety-related. Regulatory Position C.1 of RG 1.29 is not applicable because the FHAVS is not credited with the mitigation of the FHA, and therefore, it is not required to remain functional after an SSE. The evaluation of the FHAVS for interaction with seismic Category I systems discussed in Section 3.7.3 of this report finds that the VAS complies with Regulatory Position C.2 of RG 1.29. The evaluation demonstrates that seismic failure of the FHAVS does not reduce the functioning of the safety-related plant features. System equipment and ductwork located in the nuclear island, the failure of which could affect the operability of safety-related systems or components, are designed to seismic Category II requirements. The remaining portion of the system is nonseismic. Because the AABVS is not credited for any DBA conditions, it is not required to remain functional after an SSE. The makeup pump and RNS pump room coolers and exhaust fans for the AABVS are located in the seismic Category I auxiliary building. Therefore, the VAS complies with the requirements of GDC 2.

As stated previously in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with the other nuclear power units. Therefore, the VAS meets the requirements of GDC 5.

As discussed above, the subsystems' unfiltered but monitored exhaust is routed to the plant vent during normal operation. If high radioactivity is detected, the VFS filters the subsystems' exhaust, which is then routed to the plant vent. This procedure complies with the guidelines of RG 1.140 for controlling the release of radioactivity, as discussed in DCD Tier 2, Chapter 1, Appendix 1A. As discussed in Section 9.4.7 of this report, the design, construct, and testing of the VFS filtration units conform to ASME/ANSI AG-1-1997 and Addenda AG-1a-2000, ASME N-509 and N-510 standards, and the guidelines of RG 1.140, Revision 2. Therefore, the VAS also complies with the requirements of GDC 60, as they relate to the capability of the system to suitably control the release of gaseous radioactive effluents to the environment.

The VFS filtration units, which filter the VAS radioactive exhaust, conform to Regulatory Position C.4 of RG 1.13, as discussed in DCD Tier 2, Chapter 1, Appendix 1A. Consequently, the system complies with the requirements of GDC 61, as they relate to the capability of the system to provide appropriate containment, confinement, and filtering to limit releases of airborne radioactivity to the environment.

The staff evaluated the VAS for conformance with GDC 2, 5, 60, and 61, as referenced in SRP Sections 9.4.2 and 9.4.3. As discussed above, the staff found that the VAS meets the requirements of GDC 2, 5, 60, and 61. Therefore, the staff concludes that the VAS design is acceptable.

9.4.4 Balance-of-Plant Interfaces

The AP1000 is a complete design; therefore, balance-of-plant interfaces are not applicable to this design.

9.4.5 Engineered Safety Features Ventilation System

The staff evaluated the non-safety-related HVAC systems against the RTNSS criteria. The staff concludes that none of the HVAC systems are engineered safety feature (ESF) ventilation systems, and that no HVAC system is required to support non-safety-related systems determined to be important by the RTNSS process, on the basis of the following:

- Except for the VES and portions of the VBS, the HVAC systems are not safety-related and are not RTNSS systems. The portions of the VBS that are part of the RTNSS process consist of the short-term administrative controls provided for the MCR ancillary fans (as discussed in Section 22.5.7 of this report). The safety-related VES is credited with meeting the requirements of GDC 19 during a design-basis LOCA. Section 6.4 of this report evaluates the safety-related VES.

- The VBS provides safety-related design-basis functions to (1) monitor the air supply for radioactive particulate and iodine concentrations inside the MCRE, and (2) isolate the safety-related, seismic Category I HVAC piping penetrating the MCRE upon detecting "high-high" particulate or iodine radioactivity in the supplied air. The VBS is non-safety-related except as described above and is not credited with meeting the requirements of GDC 19 during a design-basis LOCA. Section 9.4.1 of this report evaluates the non-safety-related VBS.

- The VFS is not required to mitigate the consequences of a design-basis FHA or a LOCA. The staff evaluated the VFS in accordance with SRP Section 9.4.5, "Engineered Safety Features Ventilation System." The system serves no safety-related function other than containment isolation, and its operation is not required following a DBA. Section 9.4.7 of this report evaluates the non-safety-related VFS.

- No other non-safety-related HVAC systems are credited in the accident dose analyses or provide any safety-related design-basis functions. Sections 9.4.2, 9.4.3, 9.4.6, and 9.4.8 through 9.4.11 of this report evaluates other HVAC systems.

9.4.6 Containment Recirculation Cooling System

The staff reviewed the VCS in accordance with SRP Section 9.4.5. Conformance with the SRP acceptance criteria forms the basis for determining whether the VCS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes

- GDC 4, regarding maintaining environmental conditions in essential areas compatible with the design limits of the essential equipment located in those areas during normal, transient, and accident conditions

- GDC 5, regarding sharing systems and components important to safety

- GDC 17, "Electric Power System," regarding the assurance of proper functioning of essential electric power systems

- GDC 60, regarding the capability to suitably control release of gaseous radioactive effluents to the environment

The VCS is a non-safety-related ventilation system that is not required to mitigate the consequences of a DBA or LOCA. If the VCS is available following abnormal operational transients, fan coil units can operate at slow speed for postevent recovery operations to lower the containment temperature and pressure. A maintenance space ventilation subsystem with a portable exhaust filtration unit supplements the VCS. Used during shutdown and refueling operation, this subsystem protects maintenance personnel and controls the spread of airborne contamination from the steam generator compartments to the other containment areas. During integrated leak rate testing (ILRT) operation, the VCS fans are operated at slow speed in order not to exceed their rated horsepower, which could affect the ILRT results.

The VCS operates during normal plant operation and shutdown to maintain suitable temperatures in the served areas of the containment building. The two fan coil unit (FCU) assemblies are located on a platform at Elevation 153'-0", approximately 180 degrees apart to provide proper mixing of return and supply air. The top of the ring header is at Elevation 176'-6". System equipment and ductwork located in the nuclear island, the failure of which could affect the operability of safety-related systems or components, are designed to seismic Category II requirements. The remaining portion of the system is nonseismic.

DCD Tier 2, Section 9.4.6, Table 9.4.6-1, and Figure 9.4.6-1, provides the system description, component design parameters, and P&ID. Table 9.4-1 of this report describes the industry standards applicable to the components of the VCS. The VCS airflow is balanced in accordance with SMACNA-1993, "HVAC Systems—Testing, Adjusting, and Balancing."

The VCS maintains temperatures in the served areas below 48.9 °C (120 °F) during normal operation. The VCS also maintains the reactor cavity area average concrete temperature at 65.6 °C (150 °F), with a local area temperature of 93.3 °C (200 °F). During refueling and plant shutdown, the bulk air temperature of the served areas is maintained below 21.1 °C (70 °F) and above 10 °C (50 °F) for personnel access and equipment operability.

As stated in DCD Tier 2, Section 9.4.6.2 and Table 9.4.6-1, and as shown in DCD Tier 2, Figure 9.4.6-1, the VCS has two 100-percent FCU assemblies, each with two separate, but physically connected, 50-percent capacity FCUs. Each FCU assembly draws air from the upper levels of the operating floor and delivers tempered air through the ring header and the secondary duct distribution system to the cubicles, compartments, and access areas above and below the operating floor, including the reactor cavity and reactor support areas. As the tempered air absorbs the heat released from the various components inside containment, return air rises through vertical passages and openings where it is again returned to the FCUs, tempered, dehumidified, and recirculated.

Each FCU assembly consists of two 50-percent capacity FCUs. Each FCU contains a vane axial, upblast, direct-driven fan with a two-speed motor; return air mixing plenum section with a physical barrier in the middle; and three chilled water cooling coils attached to the side of each plenum section. The fans operate on high speed during normal operation and low speed for high ambient air density conditions, such as during ILRT and abnormal post-event recovery operation.

The VWS supplies the chilled water and the VYS provides the hot. The cross-connections for VWS and VYS are located outside containment. The water piping inside containment is common to both the VWS and VYS.

To meet the environmental design criteria during various modes of VCS operation, temperature controllers in the ring headers of the corresponding FCU provide an input signal to modulate the VWS supply valves to the cooling coils to maintain the normal air supply at 15.6 °C (60 °F). The standby FCUs start automatically if the discharge flow rate from the operating FCU drops below a predetermined setpoint, if the discharge temperature from the operating FCU rises above or drops below a predetermined setpoint, and if the system loses electrical and/or control power. The FCU fans are connected to 480-V buses with backup power supply from the onsite standby DGs.

A steam generator maintenance space ventilation subsystem is employed through the compartment supply air ducts during reactor shutdown for personnel access and maintenance activities. This vacuum system protects personnel and controls the spread of airborne radioactive contamination from the steam generator compartments to the other containment areas. The subsystem consists of permanently installed exhaust ductwork with flexible hose connections in the vicinity of steam generator channel heads, which can connect to a portable exhaust filtration unit (which does not exhaust outside of containment). During subsystem operation, closing relevant supply dampers will isolate the supply air distribution ductwork.

DCD Tier 2, Section 7.3 describes the VCS instrumentation. The VCS is monitored by the plant monitoring system and controlled by the plant control system. The indication of the operational status and controls for the equipment inside the containment are provided in the MCR. Temperature indications and alarms provided in the equipment compartment or areas of the containment maintain the supply air temperature within a predetermined range.

Monitoring of the containment and equipment compartment temperatures occurs from the MCR. The FCU discharge flow is monitored, and a low-flow alarm alerts the MCR operator to start the spare FCU manually. The reactor cavity areas are also monitored and alarmed for low-flow condition.

Regulatory Position C.1 of RG 1.29 does not apply to the VCS because the system is not designed to perform any safety functions. Instead, the VCS complies with Regulatory Position C.2 of RG 1.29 for the following reasons:

- System equipment and ductwork located in the nuclear island, the failure of which could affect the operability of safety-related systems or components are designed to seismic Category II requirements. The remaining portions of the system are nonseismic.

- DCD Tier 2, Section 3.7.3.13, evaluates the VCS for interaction with seismic Category I systems to ensure that the VCS does not reduce the functioning of any safety-related plant features. Section 3.7.3 of this report evaluates seismic interaction.

The staff finds this meets Regulatory Position C2 of RG 1.29 and is acceptable. Therefore, the system complies with the requirements of GDC 2.

As stated previously in Section 9.4 of this report, the HVAC system design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VCS meets the requirements of GDC 5.

The staff determined that the VCS is not an ESF system, the system is not credited with analyzing the consequences of DBA, and the system does not exhaust to the environment. Therefore, the requirements of GDC 4, 17, and 60 are not applicable.

The staff has evaluated the VCS for conformance with GDC 2, 4, 5, 17 and 60 as referenced in SRP Section 9.4.5 and finds that the VCS meets the applicable GDC. Therefore, the staff concludes that the VCS design is acceptable.

9.4.7 Containment Air Filtration System

The staff reviewed the VFS in accordance with SRP Section 9.4.5. Conformance with the SRP acceptance criteria forms the basis for determining whether the VFS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes
- GDC 4, regarding maintaining environmental conditions in essential areas compatible with the design limits of the essential equipment located in those areas during normal, transient, and accident conditions
- GDC 5, regarding sharing systems and components important to safety
- GDC 17, regarding the assurance of proper functioning of essential electric power systems
- GDC 60, regarding the capability to suitably control release of gaseous radioactive effluents to the environment
- GDC 61, regarding the capability of the system to provide appropriate containment, confinement, and filtering to limit releases of airborne radioactivity to the environment

The VFS is not required to mitigate the consequences of a design-basis FHA or a LOCA. The system serves no safety-related function other than containment isolation, and its operation is not required following a DBA. The containment isolation components are safety Class B and seismic Category I, and the quality assurance requirements of 10 CFR Part 50, Appendix B are applicable.

The components include air-operated, fail-close (during loss of power or loss of air pressure) containment isolation valves (CIVs), penetrations, interconnecting piping, and vent and test connections with manual valves. The supply and exhaust air lines that penetrate the containment pressure boundary are 914.4 mm (36 in.) in diameter. Each penetration includes inboard and outboard branch connections with 406.4-mm (16-in.)-diameter CIVs that are opened when the VFS is aligned to containment. The other ends of the containment penetrations are capped with 914.4-mm (36-in.)-diameter blind flanges for installation provisions for a high-volume purge system on a site-specific basis.

The seismic Category I debris screens are designed for post-LOCA pressures and mounted on safety Class C, seismic Category I piping between the containment atmosphere and the CIVs. This prevents entrainment of debris through the supply and exhaust opening that may prevent a tight valve shutoff against the containment pressure. The CIVs in the supply and exhaust air subsystems automatically close when they receive a containment isolation signal or a containment area high-radiation signal. The CIVs are designed to shut tightly when subject to the containment pressure following a DBA. Section 6.2.4 of this report evaluates the containment isolation function and finds it acceptable.

The VFS also provides the following functions:

- control of flow of outdoor air for containment purging to reduce the airborne radioactivity to an acceptable level for personnel access intermittently during normal plant operation and continuously during hot or cold plant shutdown conditions
- containment pressure control within its normal design pressure range by intermittent venting of air into and out of the containment
- filtration of exhaust air before discharge to the plant vent in accordance with the guidelines of 10 CFR Part 50, Appendix I for offsite releases and 10 CFR Part 20 allowable effluent concentration limits, when combined with other gaseous effluent releases, for the site boundary release
- monitoring of gaseous, particulate, and iodine concentration levels discharged to the environment through the plant vent
- conditioning and filtration of outside air to provide a comfortable environment for personnel inside the containment during access for maintenance and refueling operations
- filtration of exhaust air from the fuel-handling area, and auxiliary or annex buildings, and maintenance of these areas at a slight negative pressure with respect to the adjacent clean areas through the VFS exhaust air subsystem

The VFS is designed to maintain the supply air temperature range between 10 °C and 21.1 °C (50 °F and 70 °F) inside containment, depending on maximum and minimum normal outside temperature conditions shown in DCD Tier 2, Table 2-1. The VCS distributes and conditions the supply air within the containment.

The VFS supply air subsystem airflow is measured and balanced in accordance with SMACNA-1993. The VFS containment isolation valves, which are located in the auxiliary and containment buildings, conform to ASME Section III, Class 3, for Class B valves and B31.1 for Class D valves.

The non-safety-related portions of the VFS are designed to accomplish their intended functions assuming a single active failure and a LOOP event. The VFS consists of two 100-percent capacity, 1.9 m^3/s (4000 cfm) supply and exhaust air subsystems. Each train consists of a supply AHU, ducted air supply, registers, valves and piping, automatic controls, and accessories. Each of the exhaust air systems consists of filtration units, exhaust fans, valves and piping, automatic controls, and accessories. Exhaust air subsystems also contain common containment isolation valves and piping prior to the inlet of the air filtration units and common exhaust leading to the plant vent. A gaseous radiation monitor, located downstream of the exhaust air filtration units in the common ductwork, activates an alarm in the MCR when the monitor detects excess activity in the effluent discharge. The plant vent exhaust flow is monitored for gaseous, particulate, and iodine releases to the environment. Section 11.5 of this report describes the radiation monitoring system.

The supply AHUs are located in the south air handling equipment room of the annex building at Elevation 158'-0". The exhaust filtration units are located within the radiologically controlled portion of the annex building at Elevation 135'-3" and Elevation 146'-3". The common air intake plenum #3 for the supply and makeup air for the exhaust fan (which is not protected from turbine missiles) is located at the extreme south end of the annex building between Elevation 158'-0" and Elevation 180'-0". The ductwork located inside containment, the potential failure of which could affect safety-related equipment, is designed to seismic Category II requirements. DCD Tier 2, Section 9.4.7, Tables 3.2-3, 9.4-1, and 9.4.7-1, and Figure 9.4.7-1, respectively, provide the VFS description, P&IDs, and component design parameters. Table 9.4-1 of this report describes the industry standards applicable to the components of the VFS.

Each supply AHU consists of a low-efficiency filter, a high-efficiency filter, a hot water heating coil with integral face and bypass dampers, a chilled water cooling coil, a supply air fan, and associated I&C. Modulating the supply fan inlet vanes to compensate for filter loading or changes in containment pressure controls the AHU airflow rate to a constant value. Temperature sensors located in the supply air duct control the discharged air through each AHU. When the supply air temperature is low, the integral face and bypass dampers across the hot water heating coil bank are modulated to heat the supply air. When the supply air temperature is high, the chilled water flow is modulated to maintain the desired temperature in the area. A smoke alarm located in the common discharge ductwork downstream of the AHUs continuously monitors the supply air.

Each exhaust air filtration unit consists of a 100-percent capacity electric heater to maintain 70 percent or less RH of the effluent air, an upstream high-efficiency filter bank, a charcoal adsorber with pre- and post-HEPA filter bank, an exhaust fan, and I&C. The postfilters downstream of the charcoal adsorbers have a DOP efficiency of 95 percent and conform to UL-900-1994, "Test Performance of Air Filter Units." The isolation dampers in the exhaust air subsystem are bubble-tight, single-blade or parallel-blade type, and conform to Air Movement and Control Association (AMCA) 500, "Testing Methods for Louvers, Dampers, and Shutters," and ASME AG-1-1997 and Addenda AG-1a-2000.

The representative samples of charcoal adsorbent are tested to verify a minimum charcoal efficiency of 90 percent, in accordance with the guidance of RG 1.140, Revision 2, at frequencies identified in the ASME N-510-1989 standard. Each HEPA filter cell is individually shop tested to verify an efficiency of at least 99.97 percent in accordance with ASME AG-1-1997. The exhaust air subsystem filtration units are designed, constructed and tested to conform with ASME AG-1-1997, ASME N-509-1989 and N-510-1989 standards, and the guidelines of RG 1.140, Revision 2.

Each charcoal adsorber is a single-tray assembly with welded construction and a 101.6-mm (4-in.) thickness Type III rechargeable adsorber cell, which conforms with IE Bulletin 80-03.

The air flow rate through the exhaust filters is controlled to a constant value when the exhaust filters are connected to the containment. Modulating the exhaust fan inlet vanes to compensate for filter loading or changes in system resistance caused by single or parallel fan operation, or a change in containment pressure, achieves this control. The containment exhaust line consists of isolation valves arranged in parallel, to restrict the airflow to maintain the exhaust plenum at a negative air pressure when the containment is positively pressurized. This prevents the exfiltration of unfiltered air bypassing the filtration unit filters.

During normal plant operation, one supply AHU provides outdoor air, which is filtered, cooled or heated, to the containment areas above the operating floor. During single subsystem operation, the operator can manually start the standby supply and exhaust air units if the operating train fails. The VWS supplies the chilled water, and the VYS supplies the hot. One exhaust fan discharges the filtered exhaust air from the containment to the atmosphere through the plant vent.

Before and during cold plant shutdown, one or both trains of the VFS can be operated to remove airborne radioactivity before personnel enter the containment. When both trains operate concurrently, the VFS provides a maximum air flow rate equivalent to 0.21 air changes per hour.

During an abnormal operation, if monitors detect high airborne radioactivity or pressure differential in the fuel-handling area, or the auxiliary or annex buildings (zone areas), the VAS is isolated from the served zone area(s), and the VFS exhaust air subsystem operates to maintain the isolated zone(s) at a slightly negative pressure with respect to adjacent clean areas. Differential pressure control dampers modulate the exhaust airflow rate to provide outside makeup air to the exhaust fan when the VFS exhaust air subsystem is connected to the VAS-served zone area(s). The VFS is automatically isolated from the containment if purging is in progress and the standby exhaust filtration train does not start. One VFS train can be manually aligned to continue containment purging while the other VFS train is aligned to exhaust effluent from the zone areas. If both exhaust filtration trains are connected to containment, one exhaust filtration train is automatically isolated from the containment and is realigned to the zone area(s). The VFS exhaust air subsystem can be manually connected to the DGs during a LOOP. The VFS is not credited for a design-basis FHA or a LOCA, but it may be used if it is operational and onsite power is available to support postevent recovery operations.

DCD Tier 2, Section 7.3 describes the VFS instrumentation. The plant control system controls the VFS, except for the CIVs, which the protection and safety monitoring system (PMS) and diverse actuation system (DAS) control. DCD Tier 2, Section 9.4.1.5, discusses the instrumentation to satisfy Table 4-2 of ASME N-509-1989 for the VFS air filtration units. The status indication and alarms monitor fans, control dampers, and control valves. Operators can remotely start all fans and AHUs or shut them down from the MCR or locally. The temperature controllers maintain the proper supply air temperature.

Operators can locally access the temperature indication and alarms for high or low supply air temperature via the plant control system and be alerted to abnormal temperature conditions for supply air and charcoal adsorbers. The flow indication and alarms are provided for equipment malfunctions. The radioactivity indication and alarms are provided in the MCR for the gaseous radioactivity in the filtration subsystem's common exhaust duct and gaseous and particulate and iodine concentrations in the plant vent. Monitors detect the pressure drops across all AHUs and exhaust air filtration unit filters (except charcoal filters), and a high-pressure drop generates an alarm in the MCR.

Sections 3.5, 3.6, and 6.2.4 of this report discuss the protection of the safety-related portions (containment isolation) of the VFS against internally and externally-generated missiles, as well as against high- and moderate-energy pipe breaks.

The staff concludes that the system's safety-related portions comply with the guidelines of Regulatory Position C.1 of RG 1.29, and the system's non-safety-related portions comply with Regulatory Position C.2 of RG 1.29, because of the following VFS design features:

- location inside seismic Category I (containment and auxiliary building), flood-protected, and tornado-missile-protected buildings
- classification of the safety-related containment isolation valves, penetrations, interconnecting piping, debris screens, and vent and test connections as seismic Category I as shown in DCD Tier 2, Table 3.2-3

System equipment and ductwork located in the nuclear island, the failure of which could affect the operability of safety-related systems or components, are designed to seismic Category II requirements to preclude them from collapsing onto safety-related equipment or structures during a SSE. The remaining portion of the system is nonseismic. In Section 3.12.3.7 of this report, the staff evaluates the VFS for interaction with seismic Category I systems and verifies that its failure does not reduce the ability of any safety-related plant features to perform their functions. Therefore, the staff finds that the system complies with the requirements of GDC 2.

The staff determined that the system is not an ESF system and that it is not credited in analyzing the consequences of a DBA, except for containment isolation. Therefore, the requirements of GDC 4 and 17 are not applicable to this system.

As stated previously in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VFS meets the requirements of GDC 5.

The filtered VFS exhaust is monitored and then routed to the plant vent in compliance with the guidelines of RG 1.140, Revision 2 for controlling the release of radioactivity. Therefore, the system complies with the requirements of GDC 60, as the relate to the system's capability to suitably control the release of gaseous radioactive effluents to the environment. The VFS filtration units, which also filter the VAS radioactive exhaust, meet the guidance of Regulatory Position C.4 of RG 1.13, which specifies that the SFP building be equipped with an appropriate ventilation and filtering system to limit the potential release of radioactive iodine and other radioactive materials. Therefore, the system complies with the requirements of GDC 61, as they relate to the system capability to provide appropriate containment, confinement, and filtering to limit releases of airborne radioactivity to the environment.

The staff has evaluated the VFS for conformance with GDC 2, 4, 5, 17, 60, and 61, as referenced in SRP Section 9.4.5, and concludes that the VFS meets the applicable GDC. Therefore, the staff concludes that the VFS design is acceptable.

9.4.8 Radwaste Building HVAC System

The staff reviewed the VRS in accordance with SRP Section 9.4.3. Conformance with the SRP acceptance criteria forms the basis for determining whether the VRS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes
- GDC 5, regarding sharing systems and components important to safety
- GDC 60, regarding the capability to suitably control release of gaseous radioactive effluents to the environment

The VRS serves the radwaste building, which includes the clean electrical/mechanical equipment room, potentially contaminated HVAC equipment room, package waste storage room, waste accumulation room, and mobile system facility. The VRS is located within the radwaste building, except for the portion that connects with the plant vent. The VRS is a non-seismic system and has no safety-related functions. The VRS is a once-through, non-safety-related ventilation system that operates at 100-percent capacity continuously, with both supply air handling units and both exhaust fans running during normal plant operation to maintain suitable temperatures in the radwaste building. During filter replacement operations, the VRS operates at 50-percent capacity, and radwaste processing operations are adjusted to obtain an acceptable temperature in the radwaste building. The location of the supply air system AHUs is in the electrical/mechanical equipment room at Elevation 100'-0" on the southwest side of the radwaste building. The exhaust air system fans are located in the HVAC equipment room at Elevation 100'-0" in the northwest corner of the radwaste building.

The VRS collects the vented discharges from potentially contaminated equipment and provides for radiation monitoring of exhaust air before its release to the environment through the plant vent stack. Section 11.5 of this report describes the radiation monitoring system.

DCD Tier 2, Section 9.4.8, Figure 9.4.8-1, and Table 3.2-3 provide the system description and components classification. As identified in DCD Tier 2, Table 3.2-3, the VRS components are non-nuclear safety class, nonseismic category, and the quality assurance requirements of Appendix B to 10 CFR Part 50 do not apply. Table 9.4-1 of this report describes the industry standards applicable to the components of the VRS.

The VRS is designed to maintain the following proper operating temperatures, depending on the maximum and minimum normal outside temperature conditions shown in DCD Tier 2, Table 2-1:

- processing areas and storage rooms control between 10 °C and 40.5 °C (50 °F and 105 °F)
- mechanical and electrical equipment rooms between 10 °C and 40.5 °C (50 °F and 105 °F)

The radwaste building is maintained at a negative pressure with respect to the ambient environment to prevent potentially unmonitored radioactive releases from the radwaste building.

The differential pressure controllers, with sensors located in the general building area and mounted outdoors with shielding from wind effects, automatically modulate the inlet vanes of the AHU supply fans to maintain negative pressure inside the radwaste building with respect to the outdoors. The electric interlocks between the large truck doors and the supply fan flow controller permit the supply air to drop to 2.832 m^3/s (6000 cfm) below the exhaust flow when any truck bay door is open to create a flow into the radwaste building through the open door.

The VRS consists of the supply air system and the exhaust air system. The VRS total flow is 8.495 m^3/s (18,000 cfm), consisting of two 4.248 m^3/s (9000 cfm) trains. The supply air system consists of two 50-percent capacity AHUs, each with a low-efficiency filter bank, a high-efficiency filter bank, hot water heating coil, chilled water coil, and a centrifugal fan with automatic inlet vanes. The VWS supplies chilled water and the VYS supplies hot. Each AHU draws 100 percent outside air through individual louvered outdoor air intakes. The two AHUs discharge into a common air supply duct distribution system that is routed through the radwaste building.

Separate cooling and heating temperature controllers with sensors in the general building area control the temperature of the air supplied by the AHUs. The cooling controllers modulate the control valves on the chilled water supply lines to the AHUs to maintain the desired temperature in the area. The heating controllers modulate the face and bypass dampers of the hot water heating coil in the AHUs to maintain the desired temperature in the area. The hot water unit heaters in the mobile facility, which are controlled by local thermostats, are provided to temper air entering the building when a roll-up door is opened. The hot water unit heater in the electrical/mechanical room operates in response to local thermostats to maintain the minimum required temperature.

The exhaust air system consists of two 50-percent capacity centrifugal fans sized to allow the system to maintain a negative pressure with respect to the adjacent areas, an exhaust air duct collection system, and automatic controls and accessories. The exhaust fans discharge to a common duct, which is routed to the plant vent. A radiation monitor records activity in the common exhaust air system discharge duct and activates an alarm in the MCR when it detects excess activity in the effluent discharge. The exhaust air collection duct inside the radwaste building exhausts air from areas and rooms where low levels of airborne contamination may be present. The exhaust connection points allow the direct exhaust of equipment located on the mobile systems. The backdraft dampers at each mobile system vent connection prevent blowback through the equipment in the event of exhaust system trip. Where potentially high levels of airborne radioactive contamination exist, mobile systems will include HEPA filtration. DCD Tier 2, Sections 11.2 and 11.4 of this report discuss the mobile processing systems.

The PLS controls the VRS, which is designed to permit periodic inspection of system components during normal plant operation (see DCD Tier 2, Section 7.1.1, which discusses the PLS). The temperature is indicated for each AHU supply air discharge duct. Local differential pressure indications and high-pressure alarms the AHU and exhaust air system air filters alert the operator to the need for filter replacement. An alarm warns of high radiation in the main exhaust duct to the vent stack. Airflow indications are provided for the AHU and exhaust fan discharge ducts, and the fan discharge ducts have low-flow alarms. The operational status indications for the fans are displayed in the MCR. From the MCR, operators can initiate or shut down the fans and AHUs. The common AHU discharge duct has an alarm for smoke.

Position-indicating lights are provided for automatic dampers. Chapter 7 of this report describes the VHS instrumentation.

Regulatory Position C.1 of RG 1.29 does not apply because the VRS is not designed to perform any safety-related functions. The VRS complies with Regulatory Position C.2 of RG 1.29 for the following reasons:

- The VRS serves no safety-related function. Failure of the system does not affect the operation of safety-related structures, systems, or components because none of these are located in the area served by the system.

- The system is non-safety-related and is not credited to operate during any abnormal plant conditions.

Therefore, the system complies with the requirements of GDC 2.

As stated previously in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VRS meets the requirements of GDC 5.

The VRS collects the vented discharges from potentially contaminated areas and provides for radioactive particulate removal and radiation monitoring of exhaust air before its release to the environment through the plant vent stack. Therefore, the system meets the requirements of GDC 60, as they relate to the system's capability to suitably control the release of gaseous radioactive effluents to the environment.

The staff has evaluated the VRS for conformance with GDC 2, 5, and 60, as referenced in Section 9.4.3 of the SRP, and concludes that the system meets these GDC. Therefore, the staff concludes that the VRS design is acceptable.

9.4.9 Turbine Building Ventilation System

The staff reviewed the turbine building ventilation system (VTS) in accordance with SRP Section 9.4.4, "Turbine Area Ventilation System." Conformance with the SRP acceptance criteria forms the basis for determining whether the VTS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes

- GDC 5, regarding sharing systems and components important to safety

- GDC 60, regarding the capability to suitably control the release of gaseous radioactive effluents to the environment

The VTS operates during startup, shutdown, and normal plant operations. The VTS consists of (1) the general area ventilation subsystem, (2) the electrical equipment and personnel work area HVAC subsystem, and (3) the local area heating and ventilation subsystem. The general area ventilation subsystem serves the operating deck, intermediate levels, and base slabs. The electrical equipment and personnel work area HVAC subsystem serves switchgear rooms 1 and 2, the electrical equipment room, the RCP variable frequency drive (VFD) power converter room, and personnel work areas (secondary sampling laboratory and office spaces at Elevation 117'-6" and Elevation 171'-0") at Elevation 149'-0" and the engineering work station at Elevation 171'-0". The local area heating and ventilation subsystem serves the lube oil reservoir room, clean and dirty lube oil storage room, toilet areas (facilities), auxiliary boiler room, and motor-driven fire pump room. The VTS maintains the air temperature of all areas inside the turbine building between 10 °C and 40.6 °C (50 °F and 105 °F), except for the personnel work areas. These areas are maintained between 22.8 °C and 25.6 °C (73 °F and 78 °F), depending on the maximum and minimum normal outside temperature conditions shown in DCD Tier 2, Table 2-1.

DCD Tier 2, Section 9.4.9, Figure 9.4.9-1, and Table 3.2-3 provide the system description and components classification. As identified in DCD Tier 2, Table 3.2-3, the VTS components are a nonnuclear safety class and nonseismic category. As such, the quality assurance requirements of Appendix B to 10 CFR Part 50 do not apply. Table 9.4-1 of this report describes the industry standards applicable to the HVAC components of the VTS.

The VTS neither serves nor supports the plant's safety-related functions; therefore, the system need not be designed to meet the guidelines of RGs 1.29 and 1.140 or to withstand the effects of an SSE. Some areas of the turbine building have a potential for radioactive contamination, but any contamination is expected to be low. Radiological monitors are provided in the turbine building to detect system leakage in the condenser air removal, SG blowdown, CCW, and main steam systems. Section 11.5 of this report discusses the radiation monitoring system (RMS).

The VTS is designed to permit periodic inspection of system components during normal plant operation. The VTS is monitored by the plant monitoring system and controlled by the plant control system. Temperature indication is provided to allow temperature surveillance of room and space temperatures in the turbine building. Controllers are provided to control the room air temperatures to within a predetermined range. Differential pressure indication and high-pressure alarms are provided for the AHU air filters.

9.4.9.1 General Area Heating and Ventilation Subsystem

The general area ventilation subsystem serves most of the turbine building and is manually controlled. The subsystem consists of roof-mounted exhaust ventilators and wall-mounted louvers. The ventilators are of the hooded, direct-driven, propeller type with pneumatically actuated backdraft dampers. The wall louvers are located at Elevation 100'-0", Elevation 117'-6", and Elevation 135'-3". During heating operation, the general area ventilation subsystem is not operated. Additionally, the operating floor wall louvers are normally closed during power operation and are manually opened during outage operations for ventilation.

The general area heating subsystem is manually or automatically controlled. The system consists of hot water unit heaters and heater fans, and provides local heating throughout the turbine building. Thermostats in the automatic mode control the system heater fan motors. The VYS supplies the hot water to the subsystem.

9.4.9.2 Electrical Equipment and Personnel Work Area HVAC Subsystem

This HVAC subsystem consists of an independent electrical equipment area HVAC system and an independent personnel work area HVAC system.

The VWS supplies the subsystem with chilled water, while the VYS supplies hot water. The subsystem maintains served areas at a slight positive pressure by mixing outside air with the recirculated air. The subsystem room thermostats control the chilled water control valves for cooling and the integral face/bypass dampers for heating.

Each independent system serving corresponding areas consists of two 50-percent AHUs located at Elevation 149'-0" of the turbine building. Each AHU consists of a mixing box section, high- and low-efficiency filters, an integral face and bypass damper, a hot water heating coil, and a chilled water cooling coil. The electrical equipment area HVAC system consists of two 50-percent capacity AHUs with a supply and return air of about 27,336 scmh (317,000 scfm) each, a ducted supply and return air system, automatic controls, and accessories. The personnel work area HVAC system consists of two 50-percent capacity AHUs with a supply and return air of about 11,457 scmh (7125) scfm each, a ducted supply and return air system, automatic controls, and accessories. Electric reheat coils, provided in the ductwork to each room, are served by the personnel work area HVAC system and maintain close temperature control. During normal operation, all AHUs operate continuously.

9.4.9.3 <u>Local Area Heating and Ventilation Subsystem</u>

The lube oil reservoir room, clean and dirty lube oil storage room, toilet areas (facilities), and secondary sampling laboratory fume hood have centrifugal exhaust fans to remove flammable vapors, odors, or chemical fumes, as required.

A direct-drive, two-speed, wall exhaust ventilator is provided for each of the auxiliary boiler rooms and the motor-driven fire pump room. The ventilators are of the two-speed, propeller type with pneumatically actuated backdraft dampers. The air is pulled from the general area of the turbine building through the fire damper openings and exhausted to the atmosphere. Each exhaust ventilator is automatic or manually controlled. In the automatic mode, the exhaust ventilator motor is controlled by a two-stage room thermostat. In the manual mode, the exhaust fan runs continuously at high speed until it is stopped manually.

The motor-driven fire pump room is heated by the hot water-to-unit heater supplied from the VYS for fire pump freeze protection. The fan motors of the hot water unit heater are controlled by a thermostat during automatic mode; the heater fans run continuously in manual mode.

The auxiliary boiler room does not provide hot water heating. The auxiliary boiler room exhaust fan pulls air from the general area of the turbine building. A heating thermostat is provided in the boiler room to control the operation of the fan when the temperature falls below 10 °C (50 °F). The boiler room exhaust fan starts at low speed and continues to run until the temperature in the space rises above 10 °C (50 °F).

9.4.9.4 <u>Conclusions</u>

Because the VTS is nonseismic and is not designed to perform any safety functions, it is not required to comply with Regulatory Position C.1 of RG 1.29. The VTS does comply with Regulatory Position C.2 of RG 1.29 as follows:

- The VTS serves no safety-related function. Failure of the system does not affect the operation of safety-related structures, systems, or components because none of these are located in the area served by the system.

- The system is non-safety-related and is not credited to operate during any abnormal plant conditions.

Therefore, the system complies with the requirements of GDC 2.

As stated previously in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear units. Therefore, the VTS meets the requirements of GDC 5.

As stated above, radiological monitoring is provided in the turbine building in the condenser air removal, SG blowdown, CCW, and main steam systems to detect system leakage for any potential radioactive contamination. Section 11.5 of this report discusses the RMS. Temporary barriers are provided around the SG blowdown system (BDS), CCS, and condensate polishing areas for radiological protection. Therefore, the system is in compliance with the requirements of GDC 60.

As described above, the staff evaluated the VTS to determine its conformance with the requirements of GDC 2, 5, and 60, as referenced in SRP Section 9.4.4, and found that the VTS meets these requirements. Therefore, the staff concludes that the VTS design is acceptable.

9.4.10 Diesel Generator Building Heating and Ventilation System

The staff reviewed the DG building heating and ventilation system (VZS) in accordance with SRP Section 9.4.5. Conformance with the SRP acceptance criteria forms the basis for determining whether the VZS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes

- GDC 4, regarding the compatibility of the environmental conditions in essential areas with the design limits of the essential equipment located therein during normal, transient, and accident conditions

- GDC 5, regarding sharing systems and components important to safety

- GDC 17, regarding the assurance of proper functioning of essential electric power systems

- GDC 60, regarding the capability to suitably control the release of gaseous radioactive effluents to the environment

The VZS serves the standby DG rooms, electric equipment service modules, and diesel fuel oil day tank vaults in the DG building, as well as the two diesel oil transfer modules located in the yard. The VZS consists of the normal heating and ventilation subsystem, the standby exhaust ventilation subsystem, the fuel oil day tank vault exhaust subsystem, and the diesel oil transfer module enclosures ventilation and heating subsystem.

As identified in DCD Tier 2, Table 3.2-3, the VZS components are a nonnuclear safety class and nonseismic category. As such, the quality assurance requirements of Appendix B to 10 CFR Part 50 do not apply. DCD Tier 2, Section 9.4.10 and Figure 9.4.10-1, respectively, provide the system description and layout drawings. Table 9.4-1 of this report describes the industry standards applicable to the HVAC components of the VZS.

The two redundant DGs and associated equipment that provide standby ac power in the event of a LOOP are located in separate rooms of the non-safety-related DG building. Each DG room is served by an independent train of the VZS that provides normal heating and ventilation to continuously maintain acceptable environmental conditions when the DGs are not operating. The standby exhaust ventilation portion of the VZS functions when the corresponding DG is in operation to maintain acceptable temperatures for equipment operation and reliability. This allows for the onsite standby power system to perform its defense-in-depth function. Within each DG room, an electrical equipment service module houses the DG electrical and control support equipment. Each DG has its own dedicated diesel oil transfer module with an enclosure and is located in the yard. The DGs are not safety-related and are not essential for the safe shutdown of the plant. The VZS, which supports the operation of the DGs, is also not safety-related.

The VZS is designed to maintain the temperature inside the DG area between 10 °C (50 °F) and 40.6 °C (105 °F) when the DG is not operating, and a maximum of 54.4 °C (130 °F) when the DG is operating. In DCD Tier 2, Section 8.3.1.1.2.1, the applicant stated that the DGs will be procured to be consistent with the VZS (i.e., with a design requirement of a maximum of 54.4 °C (130 °F) when the DG is operating), as described in DCD Tier 2, Section 9.4.10.

The VZS also maintains the temperature inside the electrical equipment service modules between 10 °C (50 °F) and 40.6 °C (105 °F) at all times. Each dedicated diesel oil transfer module is maintained between 10 °C (50 °F) and 40.6 °C (105 °F) inside an enclosure. Two electric unit heaters are provided in each DG room, which maintain the space at 10 °C (50 °F) when the DGs are not operating. The VZS is designed for ambient conditions of -20.6 °C to 35 °C (-5 °F to 95 °F), which equals the 5 percent exceedance values.

Each train of the normal heating and ventilation subsystem consists of one 100-percent capacity engine room AHU that ventilates the DG room, one 100-percent capacity service module AHU that ventilates the electrical equipment service module, an exhaust system for the DG room, an exhaust system for the fuel oil day tank vault, and two electric unit heaters in the DG area. The engine room AHUs are located above the electrical equipment service module with HVAC ducting into the DG rooms. The service module AHUs are located above the service module with HVAC ducting into the module. Outside air is supplied to each AHU through a wall-mounted fixed louver. Air intake louvers are located as high in the DG building wall as possible, which meets the intent of the guidance of NUREG/CR-0660, "Enhancement of Onsite Emergency Diesel Generator Reliability," to control the dust and other particulates for conformance with GDC 17, as it relates to ensuring proper functioning of the standby onsite ac electric power system.

Each AHU of the normal heating and ventilation subsystem consists of a mixing box section, a high-efficiency filter bank, a low-efficiency filter bank, and a centrifugal fan. During normal plant operation, the engine room AHU runs continuously when the DG is off and outdoor air is required for room cooling. The space thermostats control the proportion of outside air that is mixed with return air to maintain adequate temperature in the areas served by the engine room. The excess outside air supplied to the engine room is discharged to the outdoors via a gravity relief damper.

Each service module AHU has an electrical heating coil that is controlled by a separate space thermostat. The outside air is supplied to each AHU through a wall-mounted fixed louver. The excess outside air from the service module flows into the diesel engine area via a wall-mounted relief damper. The service module AHU operates continuously regardless of the DG status.

Each train of the standby exhaust ventilation subsystem consists of two 50-percent capacity roof-mounted exhaust fans and two motor-operated air intake dampers mounted in the exterior walls of the room. The exhaust fans turn on when the DGs start and turn off when the DGs stop. The standby exhaust fans are actuated by a DG start signal, as shown in DCD Tier 2, Figures 9.4.10-1 and 9.4.10-2. The motor-operated air intake dampers open and close in conjunction with the operation of the exhaust fans. One or both standby exhaust fans are required to operate to maintain the engine room temperature in reference to ambient temperature. The subsystem is required to operate to support DG operation during a LOOP.

Each fuel oil day tank vault is continuously ventilated by a 100-percent capacity centrifugal exhaust fan. The exhaust fans are roof-mounted and ducted to draw air from 0.3 m (1 ft) above the vault floor to remove any oil fumes generated in the space. Air is drawn into each fuel oil tank vault from the DG room through a fire damper. The fans are manually operated.

The diesel oil transfer module enclosures are serviced by a separate exhaust ventilation system. Each diesel oil transfer module enclosure is ventilated by a 100-percent capacity, roof-mounted exhaust fan. Outside air is drawn into the enclosure through manually operated louvered air intakes; these louvers are closed during winter operation when heating is required. An electric unit heater is provided in each enclosure to maintain the space at a minimum temperature of 10 °C (50 °F). The subsystem is required to operate to support DG operation during a LOOP.

Because the VZS has two 50-percent capacity exhaust fans for each DG room and one 100-percent capacity AHU for each service module, at least one DG train will be fully operational should a single fan failure occur.

The system design allows for periodic inspection of the system's components (see DCD Tier 2, Section 7.1.1, for the plant control system). The system temperature indication and alarms are accessible locally via the plant control system. The operational status indications for the fans are provided in the MCR. All fans and AHUs can be operated locally or from the MCR. The AP1000 design provides for a differential pressure indication for each filter in the AHUs and a high-pressure drop alarm for each AHU.

Because the VZS is not designed to perform any safety functions, it is not required to comply with Regulatory Position C.1 of RG 1.29. However, the VZS does comply with Regulatory Position C.2 of RG 1.29 as follows:

- The VZS serves no safety-related function. Failure of the system does not affect the operation of safety-related structures, systems, or components because none of these are located in the area served by the system.

- The system is non-safety-related and is not credited to operate during any abnormal plant conditions.

Therefore, the system design complies with the requirements of GDC 2.

The VZS is not required to maintain a controlled environment in areas containing safety-related equipment, and areas served by the VZS do not contain equipment essential for the safe shutdown of the reactor or necessary to prevent or mitigate the consequences of a DBA. Therefore, GDC 4 is not applicable to the VZS.

As stated previously in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VZS meets the requirements of GDC 5.

The onsite standby power system (ZOS) includes two DGs housed in the non-safety-related DG building. The applicant states that the ZOS and DGs are not safety-related; therefore, they are not essential for the safe shutdown of the reactor, nor are they necessary to prevent or mitigate the consequences of a DBA. The applicant further states that the VZS is physically separated from potentially contaminated areas and does not contain any radioactive materials. Therefore, the VZS is not required to comply with the recommendations of RGs 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," and 1.140, or the requirements of GDC 60.

The staff has evaluated the VZS for conformance with the requirements of GDC 2, 4, 5, 17, and 60, as referenced in SRP Section 9.4.5, and concludes that the VZS meets the applicable GDC. Therefore, the staff concludes that the VZS design is acceptable.

9.4.11 Health Physics and Hot Machine Shop HVAC System

The staff reviewed the VHS in accordance with SRP Section 9.4.3. Conformance with the SRP acceptance criteria forms the basis for determining whether the VHS satisfies the following requirements:

- GDC 2, regarding the capability to withstand earthquakes
- GDC 5, regarding sharing systems and components important to safety
- GDC 60, regarding the capability to suitably control release of gaseous radioactive effluents to the environment

The VHS collects the vented discharges from potentially contaminated sumps and equipment in the health physics area, as well as exhaust from welding booths, grinders, and other equipment located in the hot machine shop. It also monitors exhaust air for radiation before its release to the environment through the plant vent stack. Section 11.5 of this report describes the RMS.

The VHS serves no plant safety-related functions, and there are no safety-related SSCs in the area serviced by the system. The VHS is a once-through, non-safety-related ventilation system that operates only during the normal modes of plant operation. The VHS is located within the annex building, except for the portion of that system that connects with the plant vent. The VHS serves both the health physics/access control area in the annex building located at Elevation 100'-0" and the hot machine shop located at Elevation 107'-2" in the annex building. These areas are maintained at a slight negative pressure with respect to the outdoors and clean areas to ensure that all potentially radioactive releases are monitored before discharge.

The supply air subsystem AHUs are located in the lower south air handling equipment room at Elevation 135'-3" of the annex building. The exhaust air subsystem fans are located in the staging and storage areas at Elevation 135'-3" of the annex building.

As identified in DCD Tier 2, Table 3.2-3, the VHS components are a nonnuclear safety class and nonseismic category. As such, the quality assurance requirements of 10 CFR Part 50, Appendix B do not apply. DCD Tier 2, Section 9.4.11 and Figure 9.4.11-1 present the system description and layout drawings, respectively. Table 9.4-1 of this report describes the industry standards applicable to the HVAC system components of the VHS.

The VHS maintains the direction of air flow from areas of low potential radioactivity to areas of higher potential radioactivity. The VHS is designed to maintain the temperature of the health physics area at 22.8 °C to 25.6 °C (73 °F to 78 °F), and the hot machine shop at 18.3 °C to 29.4 °C (65 °F to 85 °F), depending on the maximum and minimum normal outside temperature conditions shown in DCD Tier 2, Table 2-1. The VHS is designed to maintain a minimum relative humidity of 35 percent in normally occupied areas via a steam humidifier located in the main system supply duct. The water for the system humidifier is provided by the demineralized water system.

The differential pressure controllers, with sensors in the general health physics area and sensors mounted outdoors (shielded from wind effects), modulate the automatic inlet vanes of the supply fan to maintain the area at a negative pressure with respect to the surrounding areas. A separate differential pressure controller, with a sensor in the hot machine shop, modulates a damper in the supply air duct to the hot machine shop to maintain a negative pressure with respect to the outdoors.

The VHS consists of the supply air subsystem and the exhaust air subsystem. The supply air subsystem consists of two 100-percent capacity (22,512 scmh each (14,000 scfm each)) AHUs, each with a low- efficiency filter bank and a high-efficiency filter bank; a hot water heating coil; a chilled water cooling coil bank; a centrifugal fan with automatic inlet vanes, associated dampers, and I&C; and ductwork. Each AHU draws 100 percent outside air through a common louvered outdoor air intake plenum #2, as described in DCD Tier 2, Section 9.4.2. The two AHUs discharge into a distribution system to the health physics and hot machine shop areas. The temperatures in the health physics and hot machine shop areas are maintained within the design range by a temperature sensor located in the health physics area. This sensor modulates the control valve on the chilled water supply lines to the cooling coil and the face and bypass dampers of the hot water heating coil. The supply of the chilled and hot water is provided by the VWS and VYS, respectively.

The exhaust air subsystem consists of two 100-percent capacity centrifugal exhaust fans, sized to maintain a negative pressure with respect to the adjacent areas, with ductwork and automatic controls. A separate machine shop exhaust fan and high-efficiency filter are provided for the machine tools and other localized areas in the hot machine shop. The air flow rates are balanced to maintain a constant exhaust air flow across the fans. The exhaust fans discharge to a common duct, which is routed to the plant vent stack. Individual flexible exhaust duct branches are provided to the machine tools area. The flexible ducts are connected to a hard duct manifold, which is connected to a filter and a fan. The exhaust fan discharges into the main system exhaust ductwork.

Should a single failure occur, one supply AHU and one exhaust fan are capable of maintaining corresponding areas at the designed temperatures, at a slight negative pressure, and with the direction of system air flow from areas of low radioactivity to areas of high radioactivity.

The health physics area, including the hot machine shop, is monitored by a non-safety-related radiation monitor. The radiation monitor is located in the common VHS exhaust duct. High-radiation alarms are provided both locally and in the MCR. DCD Tier 2, Sections 9.4.11 and 11.5 and Tables 11.5-1 and 11.5-2 describe these radiation monitors.

Temperature indication is provided for each AHU supply air discharge duct. Local differential pressure indications and MCR high-pressure alarms are provided for the AHU and exhaust air system air filters. The remote manual hand switches and alarms for the system fans are provided in the MCR. The fans and AHUs can be initiated or shut down from the MCR. An alarm is provided for smoke in the common AHUs discharge duct. Position indicating lights are provided for automatic dampers.

Regulatory Position C.1 of RG 1.29 does not apply because the VHS is not designed to perform any safety functions. However, the VHS does comply with Regulatory Position C.2 of RG 1.29 as follows:

- The VHS serves no safety-related function. Failure of the system does not affect the operation of safety-related structures, systems, or components because none of these are located in the area served by the system.

- The system is non-safety-related and is not credited to operate during any abnormal plant conditions.

Therefore, the system design complies with the requirements of GDC 2.

As stated previously in Section 9.4 of this report, the HVAC design described in the DCD does not share SSCs with other nuclear power units. Therefore, the VHS meets the requirements of GDC 5.

The VHS is not safety-related, performs no safety-related function for safe shutdown or postaccident operation, and failure of the system does not affect the functions of other safety-related equipment. The lower south air handling equipment room in the annex building, where the VHS supply AHUs are located, has no sources of radioactivity during normal plant operation. The hot machine shop mezzanine area, where the hot machine shop exhaust fans are located, is not a high-radioactivity area. The shielding of components and personnel is commensurate with radiation sources in the vicinity of the VHS equipment during normal plant operation.

The VHS collects the vented discharges from potentially contaminated areas and provides for radiation monitoring of exhaust air prior to its release to the environment through the plant vent stack. Therefore, the requirements of GDC 60 are met.

The staff has evaluated the VHS for conformance with GDC 2, 5, and 60, as referenced in SRP Section 9.4.3, and concludes that the VHS meets the requirements of GDC 2, 5, and 60. Therefore, the staff concludes that the VHS design is acceptable.

Table 9.4-1 HVAC System Components

Component	Standard	Title
Supply, return, and exhaust fans	ANSI/AMCA 210-85	Laboratory Methods of Testing Fans for Rating Purposes
	ANSI/AMCA 211-87	Certified Ratings Program Air Performance
	AMCA 300-85	Reverberant Room Method of Testing Fans for Rating Purposes
Housings, ductwork, supports, and accessories	SMACNA-1980	Rectangular Industrial Duct Construction Standards
	SMACNA-1995	HVAC Duct Construction Standards—Metal and Flexible
	SMACNA-1999	Round Industrial Duct Construction Standards
	SMACNA-1985	HVAC Duct Leakage Test Manual
	Addenda AG-1a-2000	Housings
Low-efficiency filters, high-efficiency filters, and post-filters	ANSI/ASHRAE 52.1-1992	Gravimetric and Dust Spot Procedures for Testing Air-Cleaning Devices Used in General Ventilation for Removing Particulate Matter, Standards
	ASHRAE 126, 2000	Method of Testing HVAC Air Ducts
	ASHRAE 62-1999	Ventilation for Acceptable Indoor Air Quality
	UL-900, 1994	Test Performance of Air-Filter Units, Class I Criteria
Cooling coils and hot water heating coils	ANSI/ARI 410-91	Forced-Circulation Air Cooling and Air Heating Coils
	ANSI/ASHRAE 33-1978	Methods of Testing for Rating Forced Circulation Air Cooling and Air Heating Coils
Electric unit heaters	UL-1996, 1996	Electric Duct Heaters
	NFPA 70, 1999	National Electrical Code
Electric heating coils	UL-1095, 1995	Electric Central Air Heating Equipment
Humidifiers	ARI 620-96	Self-Contained Humidifiers, Standards
Dampers, isolation dampers, and containment exhaust air dampers	ANSI/AMCA 500-89	Testing Methods for Louvers, Dampers, and Shutters
	SMACNA-1993	HVAC Systems Testing, Adjusting, and Balancing
	ASME N-509-1989	Nuclear Power Plant Air-Cleaning Units and Components

Component	Standard	Title
HEPA filters and charcoal adsorbers	ASME N-510-1989	Testing Nuclear Air Cleaning Systems
	ASME N-509-1989	Nuclear Power Plant Air-Cleaning Units and Components
	ANSI/ASME AG-1-1997	Code on Nuclear Air and Gas Treatment
	UL-586, 1996	High-Efficiency, Particular, Air-Filter Units
Smoke and fire dampers	UL-555, 1999	Fire Dampers
	UL-555S, 1999	Leakage Rated Dampers for Use in Smoke Control Systems
	NFPA 90A-1999	Installation of Air Conditioning and Ventilation Systems

9.5 Other Auxiliary Systems

9.5.1 Fire Protection Program

The fire protection (FP) system detects and suppresses fires and is an integral part of the AP1000 FP program. The FP review criteria for the AP1000 are specified in SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor Designs," and SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs." In addition, 10 CFR 52.48 specifies that the design will comply with the requirements specified in 10 CFR 50.48, "Fire Protection," and GDC 3, "Fire Protection." Conformance with the SRP is addressed in 10 CFR 50.34(g), which specifies that applications include an evaluation of the facility against the SRP. BTP Chemical and Mechanical Engineering Branch (CMEB) 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," provides the FP guidance for nuclear power plants specified in the SRP.

In addition to the guidance detailed in the BTP, the staff specified in SECY-90-016, SECY-93-087, and Section 9.3 of NUREG-1242, "NRC Review of Electric Power Research Institute's Advanced Light Water Reactor Utility Requirements Document," Volume 3, that the advanced light-water reactors (ALWRs) should provide an enhanced level of FP to ensure that safe shutdown can be achieved, assuming all equipment in any one fire area is rendered inoperative as a result of fire damage and that reentry into the fire area by plant personnel for repairs or operator actions is not possible. The control room and the containment are excluded from this criterion, provided an independent alternative shutdown capability is provided for a control room fire and that FP for redundant divisions located inside containment is provided to ensure that one shutdown division will be free of fire damage following a fire inside the containment.

The design should also ensure that smoke, hot gases, and fire suppressants do not migrate into other fire areas to the extent that they could adversely affect safe-shutdown capabilities, including operator actions. In response to RAI 280.009, the applicant confirmed that when a fire was postulated in a fire area, all components in the fire area are assumed to be inoperable, whether this results from fire or smoke damage. All components in the neighboring area were also assumed to be inoperable due to fire or smoke damage.

The NRC staff interpretations and positions, discussed above, related to FP which are published in generic communications were used as applicable in the review of the AP1000. In addition, the applicant applied the latest applicable NFPA codes, standards, and recommended practices to the FP systems and features provided in the AP1000 design. To support the AP1000 design certification, the applicant submitted WCAP-15871, "AP1000 Assessment Against NFPA 804." This report compares the AP1000 design to the 2001 edition of NFPA 804, "Fire Protection for Advanced Light Water Reactor Electric Generating Plants." In response to RAI 280.003, the applicant revised the DCD and WCAP-15871 in accordance with SECY-93-087 to ensure that the AP1000 design applies the latest industry standards endorsed by the NRC in RG 1.189, "Fire Protection for Operating Nuclear Power Plants."

DCD Tier 2, Section 9.5.1, "Fire Protection System," states that the primary objectives of the AP1000 FP program are to prevent fires and to minimize the consequences should a fire occur. In DCD Tier 2, Table 9.5.1-1, the applicant provided a point-by-point comparison of the AP1000 FP program with the BTP. In addition, the FP program provides protection so that the plant can be shut down safely following a fire. The staff reviewed the AP1000 to determine its compliance with BTP CMEB 9.5-1.

The following evaluation is based on the staff's review of DCD Tier 2, Chapter 9 and Appendix 9A. All of the COL action items and deviations from BTP CMEB 9.5-1 identified and approved for the AP1000 FP program were also approved for the AP600 FP program. The staff's evaluation identified no new COL action items for the AP1000 design. Section 9.5.1.9 of this report provides a summary of all approved deviations and COL action items.

9.5.1.1 Fire Protection Program Requirements

9.5.1.1.a Fire Protection Program (Regulatory Position C.1.a of BTP CMEB 9.5-1)

The COL applicant is responsible for establishing an FP program at the facility for the protection of SSCs important to safety. The COL applicant will also establish the procedures, equipment, and personnel needed to implement the program. This is COL Action Item 9.5.1-1(a).

9.5.1.1.b Fire Hazard Analysis (Regulatory Position C.1.b of BTP CMEB 9.5-1)

The applicant has provided the fire hazard analysis for the AP1000 design in DCD Tier 2, Section 9.5.1 and Appendix 9A. This analysis demonstrates that the plant will maintain the ability to perform safe-shutdown functions, minimize radioactive releases to the environment, identify fire hazards and appropriate protection, and verify that the NRC FP guidelines (e.g., BTP CMEB 9.5-1, SRP, etc.) have been met. In RAI 280.007, the staff asked the applicant to resolve a discrepancy in Section 2.4 of WCAP-15871, which indicated that an analysis of the potential effects of a fire on the release of contamination had not been included. The applicant indicated that WCAP-15871 would be revised to reflect that the design was appropriately evaluated, as already stated in DCD Tier 2, Section 3.11, and Item 12 of DCD Tier 2, Table 9.5.1-1. The applicant issued a revision to WCAP-15871 in December 2002 which addressed the staff's concerns. The COL applicant is responsible for revising the fire hazard analysis to reflect the actual plant configuration. This is COL Action Item 9.5.1-2.

The staff has determined that the following design commitments included in the DCD Tier 2 figures identified below will require NRC review and approval prior to implementation of any design change sought by a COL applicant or licensee. The commitments identified below should be listed as Tier 2* information in the proposed rule certifying the AP1000 design.

AP1000 DCD	DESCRIPTION
Figure 9A-1	Nuclear Island Fire Area Plan
Figure 9A-2	Turbine Building Fire Area Plan
Figure 9A-3	Annex I & II Building Fire Area Plan
Figure 9A-4	Radwaste Building Fire Area Plan
Figure 9A-5	Diesel Generator Building Fire Area Plan

9.5.1.1.c Fire Suppression System Design Basis (Regulatory Position C.1.c of BTP CMEB 9.5-1)

The fire suppression systems located inside the containment and outlying buildings are subject to a single active failure or crack that could impair both the primary and backup fire suppression capabilities. This is not consistent with the guidance specified in BTP CMEB 9.5-1. The fire suppression systems located inside the containment are qualified to seismic Category I criteria, which reduces the potential for a failure of the system. The buildings outside containment do not contain safety-related equipment or present an exposure hazard to structures containing safety-related equipment. Manual fire suppression capability using hose lines connected to the outside hydrants of the yard main can be provided in the event of a failure of the interior fire suppression systems. On the basis of the seismic qualification of the fire suppression system located inside containment, the absence of safety-related equipment in the outlying buildings, and the manual suppression capability using the outside hydrants, the staff concludes that this alternative means of fire protection is acceptable.

The staff also concludes that the applicant identified no other exceptions to the guidance specified in BTP CMEB 9.5-1 related to the design basis for the fire suppression system. Therefore, the staff concludes that the design of the AP1000 fire suppression system is acceptable. This is Deviation 9.5.1-1.

9.5.1.1.d Alternative/Dedicated Shutdown (Regulatory Position C.1.d of BTP CMEB 9.5-1)

The staff identified in RAI 280.004 that Items 75 and 76 of DCD Tier 2, Table 9.5.1-1, stated that alternative or dedicated shutdown capability were not necessary. These statements are incorrect and inconsistent with the staff's position in BTP CMEB 9.5-1 on alternative/dedicated shutdown. Therefore, the applicant revised the information in DCD Tier 2, Table 9.5.1-1, to remain consistent with the staff's alternative/dedicated shutdown position developed for the AP1000. The staff has determined that the applicant did remain consistent with the staff's position, as identified in DCD Tier 2, Chapter 9 and Table 9.5.1-1.

9.5.1.1.e Implementation of Fire Protection Program (Regulatory Position C.1.e of BTP CMEB 9.5-1)

The COL applicant is responsible for implementing an FP program prior to receiving fuel on site for both the fuel storage areas and the entire unit prior to reactor startup. This is COL Action Item 9.5.1-1(b).

9.5.1.2 Administrative Controls (Regulatory Position C.2 of BTP CMEB 9.5-1)

The COL applicant is responsible for establishing administrative controls to maintain the performance of the FP systems and personnel. This is COL Action Item 9.5.1-1(c). In addition, based on insights from the PRA, Westinghouse included a combined license item in DCD Tier 2, Section 9.5.1.8 which states that the combined license applicant will establish procedures to address a fire watch for fire areas breached during maintenance. This is COL Action Item 9.5.1-3.

9.5.1.3 Fire Brigade (Regulatory Position C.3 of BTP CMEB 9.5-1)

The COL applicant is responsible for establishing a site fire brigade trained and equipped for firefighting to ensure adequate manual firefighting capability for all plant areas containing SSCs important to safety. This is COL Action Item 9.5.1-1(d).

9.5.1.4 Quality Assurance Program (Regulatory Position C.4 of BTP CMEB 9.5-1)

The COL applicant is responsible for establishing a quality assurance program to ensure that the guidelines for the design, procurement, installation, and testing, as well as the administrative controls for the FP systems are satisfied. This is COL Action Item 9.5.1-1(e).

9.5.1.5 General Plant Guidelines (Regulatory Position C.5 of BTP CMEB 9.5-1)

9.5.1.5.a Building Design (Regulatory Position C.5.a of BTP CMEB 9.5-1)

The safety-related structures (i.e., the containment and auxiliary building NRCAs) are separated from non-safety-related structures (i.e., the turbine building, annex building, radwaste building, DG building, and auxiliary building RCAs) by barriers having a minimum fire resistance rating of 3 hours. With the exception of the control room, the remote shutdown workstation, and the containment, fire barriers with a minimum fire resistance rating of 3 hours are provided to separate redundant divisions of the passive safety-related systems.

Openings through fire barriers for pipe conduit and cable trays are sealed with noncombustible materials to provide a fire resistance rating equal to that required by the barrier, qualified in accordance with the criteria specified in BTP CMEB 9.5-1. Penetrations for ventilation systems are protected in accordance with the criteria specified in NFPA 90A. Doors installed in fire barriers are qualified in accordance with the criteria specified in NFPA 80, "Fire Doors and Windows." The COL applicant is responsible for inspecting and maintaining the fire doors, providing access to keys for the fire brigade, and marking exit routes. This is COL Action Item 9.5.1-1(f).

The use of gypsum wallboard, which the applicant proposed to install in lieu of concrete to enclose those personnel access and egress routes meeting the criteria of BTP CMEB 9.5-1, was unresolved and was identified as Open Item 9.5.1-1 in the DSER. In various letters and DCD revisions, the applicant proposed concrete/steel composite material to enclose all personnel access or egress routes in the AP1000 design. Section 9.5.1.9 of this report provides a more detailed discussion of the applicant's proposed concrete/steel composite material for stair towers.

The AP1000 design has no cable spreading rooms. Therefore, the guidance specified in BTP CMEB 9.5-1 addressing the separation of cable spreading rooms is not applicable. In addition, the AP1000 design does not use gaseous suppression systems. Therefore, the guidance specified in BTP CMEB 9.5-1 addressing gaseous suppression systems is not applicable.

Interior finish, wall, ceiling, structural components, thermal insulation, radiation shielding, and soundproofing materials used in the AP1000 are noncombustible. Metal deck roof construction is noncombustible and listed as Class I in the Factory Mutual Research Corporation (FMRC) Approval Guide, "Equipment, Materials, Services for Conservation of Property."

The cables used in the plant are qualified in accordance with the criteria specified in Institute for Electrical and Electronic Engineers (IEEE) Std 1202, "Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies." During its review of the AP600, the staff approved the use of the 25.4-cm (10-in.) -wide ribbon burner specified in IEEE 383, "IEEE Standard for Qualifying Class 1E Electric Cables and Field Splices for Nuclear Power Generating Stations," and IEEE Std 1202 as the only acceptable test procedure. The applicant verified in its response to RAI 280.002 that it intended to remain consistent with the AP600 design and use only the 25.4-cm (10-in.)-wide ribbon burner cable for the AP1000. The use of the 25.4-cm (10-in.)-wide ribbon burner for testing cable for the AP1000 design is acceptable because it is in accordance with IEEE Std 383.

With the exception of the combustible cable insulation installed in the underfloor and ceiling spaces in the MCR, TSC, and remote shutdown workstation, the concealed spaces are free of combustible materials. BTP CMEB 9.5-1 specifies that concealed spaces should be devoid of combustibles. Fire detection is provided in the concealed areas containing cables. This alternative protection provides an equivalent level of safety as that specified in BTP CMEB 9.5-1 and, therefore, is acceptable. This is Deviation 9.5.1-2.

Transformers installed in safety-related areas are either of the dry type or contain a noncombustible liquid. Outdoor transformers are located at least 15.2 m (50 ft) from other structures, or are separated by blank fire walls with a minimum fire resistance rating of 3 hours. Outdoor oil-filled transformers are provided with oil containment or drainage away from structures.

Floor drains of adequate capacity are provided in areas containing safety-related equipment to remove fire suppression water discharged from fixed or manual fire suppression systems. The COL applicant is responsible for collecting and sampling water drainage from areas that may contain radioactivity. This is COL Action Item 9.5.1-1(g).

Drains installed in areas containing combustible liquids are equipped with backflow prevention to preclude the flow of combustible liquids into areas containing safety-related equipment.

The applicant identified two exceptions from the guidance specified in BTP CMEB 9.5-1. The first exception relates to the cable insulation installed in the concealed spaces of the MCR, TSC, and remote shutdown workstation. This exception is acceptable because fire protection is provided in the concealed areas containing cables. The second exception relates to the use of gypsum stair towers and is identified as Open Item 9.5.1-1 in the DSER. Section 9.5.1.9 of this report provides a detailed discussion of the applicant's proposed concrete/steel composite material which it will use in lieu of gypsum wallboard to enclose stair towers.

This exception is acceptable because the applicant's proposed concrete/steel composite material, which it will use to enclosed personnel access and egress routes, meets the criteria of BTP CMEB 9.5-1.

9.5.1.5.b Safe Shutdown Capability

9.5.1.5.c Alternative or Dedicated Shutdown Capability
(Regulatory Positions C.5.b and C.5.c of BTP CMEB 9.5-1)

The AP1000 criteria for the protection of safe and cold shutdown capability following a single fire in any fire area are as follows:

- Safe shutdown following a fire is defined for the AP1000 as the ability to achieve and maintain the RCS temperature below 215.6 °C (420 °F) without venting the primary coolant from the RCS. This is a departure from the BTP CMEB 9.5-1 criteria applied to the evolutionary plant designs and the existing plants, in which safe shutdown for fires applies to both hot and cold shutdown capability. This position is consistent with SECY-94-084 and, therefore, is acceptable. This is Deviation 9.5.1-3.

- Cold shutdown for the AP1000 is defined as the ability to achieve and maintain the RCS below 93.3 °C (200 °F), consistent with the criteria applicable to the evolutionary designs and existing plants and, therefore, is acceptable.

The use of the non-safety-related normal shutdown systems and/or the safety-related passive systems is acceptable to the staff to achieve and maintain safe shutdown following a fire. The safety-related passive systems are considered an alternate/dedicated shutdown method, as described in BTP CMEB 9.5-1, for fire areas where the normal shutdown systems have not been protected in accordance with the guidance prescribed in BTP CMEB 9.5-1. Consistent with the FP criteria for ALWRs specified in SECY-90-016 and SECY-93-087, redundant divisions of these systems shall be separated, such that a fire in any fire area outside of the containment or the MCR will not impair the plant's capability to achieve and maintain safe shutdown as defined above, assuming a loss of all equipment in the affected fire area.

Consistent with SECY-90-16, the safe-shutdown analysis may not consider personnel entry into the affected fire area to repair or operate equipment to achieve safe shutdown. Personnel entry into the affected fire area to repair or operate equipment necessary to achieve and maintain cold shutdown of the AP1000 is acceptable, because of the AP1000's unique capability to remain in safe shutdown for an extended period of time using only passive systems.

The criteria in BTP CMEB 9.5-1 concerning cold shutdown capability deviates from the criteria in SECY-93-087, SECY-94-084, and SECY-90-016 when applied to the evolutionary reactor designs, but is consistent with the criteria applicable to existing plants. To enhance the survivability of the normal safe shutdown and cold shutdown capability in the event of a fire, and to reduce the reliance on the infrequently utilized safety-related passive systems, automatic suppression will be provided in those fire areas outside containment where a fire could damage the normal shutdown capability or result in a spurious operation of equipment that could lead to a venting of the RCS. This criterion is unique to the AP1000 advanced reactor designs and does not ensure that the normal shutdown capability will be free of fire damage, or that the equipment necessary to achieve and maintain cold shutdown can be repaired within 72 hours. This is consistent with SECY-94-084 and is acceptable because the design utilizes passive safety-related systems as the alternative dedicated safe shutdown. This is Deviation 9.5.1-4.

As a result of the inability of the fire brigade to rapidly enter the AP1000 containment in the event of a fire, and the potential for damage to safety-related and normal shutdown equipment, in addition to potential spurious actuation(s) resulting in a venting of primary coolant from the RCS, the protection of circuits and equipment inside containment should be enhanced beyond the criteria specified in BTP CMEB 9.5.1 for existing plants, consistent with the staff's technical position stated in Section 9.3 of NUREG-1242.

The applicant provided adequate suppression and detection of the equipment and circuits located inside containment that are required for safe shutdown. This provides reasonable assurance that one division of safety-related equipment will remain free of fire damage, in accordance with the criteria specified in NUREG-1242. Complete fire barrier separation cannot be provided inside of containment due to the need to maintain the free exchange of gases for purposes such as passive containment cooling. The location of safety-related equipment and routing of Class 1E electrical cable in separate fire zones enhances the separation of redundant safe-shutdown components.

Hose stations for manual suppression are provided inside containment; however, because of the potential hazard associated with personnel entry into containment during a plant transient, the response of the plant fire brigade may be significantly delayed. Therefore, no credit for manual suppression of fires inside containment during power operations is considered acceptable by the staff.

In fire zone 1100 AF 11300B, the applicant provided a manually actuated water spray system over the non-safety-related open cable trays to limit smoke and heat generation. Both divisions of the passive residual heat removal (PRHR) control valves and PRHR flow transmitters are located in this zone in close proximity to each other. These valves are separated by a noncombustible steel or steel composite barrier. Separate fire detectors are provided near each valve. No exposed cables exist in fire zone 1100 AF 11300A, which is adjacent to fire zone 1100 AF 11300B. The applicant has provided reasonable assurance that one division of the normal or passive safe-shutdown capability located inside containment will be maintained free of fire damage; therefore, this aspect of the design is acceptable.

The applicant included the reactor head vents for consideration as a high/low-pressure interface, in accordance with the guidance provided in GL 81-12, "Fire Protection Rule." Inside containment, the cables for the control of one head vent valve in each flow path are routed in separate conduits to prevent a spurious actuation of both valves in the flow path. In areas outside containment (i.e., the MCR and the remote shutdown workstation), the power and control circuits are located in separate fire areas. The soft controls located in the MCR and remote workstations are not susceptible to fire-induced spurious actuation. The dedicated switches in the MCR are located on separate panels, such that a fire may short the switches on one panel but the unaffected panel will be deenergized before spurious actuation of two valves in the same flow path.

The applicant addressed the spurious actuation of the automatic depressurization system (ADS), resulting from hot shorts of the control circuits for motor-operated valves from a fire in the MCR, remote shutdown workstation, dc equipment rooms, and Class 1E penetration rooms. Separation and prompt operator actions are credited to minimize the potential for spurious actuation of the ADS. The spurious actuation of the ADS does not result in an unrecoverable plant configuration or prevent safe shutdown. In addition, as a result of insights from the PRA DCD Tier 2, Section 9.5.1.8 indicates that the combined license applicant will provide an analysis that demonstrates that operator manual actions which minimize the probability of the potential for spurious ADS actuation as a result of a fire can be accomplished within 30 minutes following detection of the fire and the procedure for the manual actuation of the fire water containment supply isolation valve to allow fire water to reach the automatic fire suppression system in the containment maintenance floor. This is COL Action Item 9.5.1-4.

As stated in its response to RAI 280.010, the applicant also considered in the AP1000 system spurious actuations of the passive safety systems, other than the ADS, due to fire, and potential spurious actuations of non-safety systems due to fire, as documented in DCD Tier 2, Section 9A.3.7.1.2. The AP1000 design does not allow the spurious actuation of a non-safety system to defeat the passive safety systems. The staff concludes, based on the above review, that the safe-shutdown capability and the alternative dedicated shutdown capabilities are acceptable.

9.5.1.5.d Control of Combustibles (Regulatory Position C.5.d of BTP CMEB 9.5-1)

Safety-related systems are separated from concentrations of combustible materials, where practical. Where separation is not possible, the design provides for appropriate FP based on the fire hazard analysis. BTP CMEB 9.5-1 specifies that bulk gas storage tanks should not be located inside structures containing safety-related equipment. However, breathing air storage tanks for the AP1000 design are located in the auxiliary building NRCA. These tanks are safety-related and are provided with overpressure protection and, therefore, are acceptable. This is Deviation 9.5.1-5. High-pressure gas storage containers are located in accordance with the guidance prescribed in BTP CMEB 9.5-1.

The COL applicant is responsible for the control of the use of compressed gases inside structures. This is COL Action Item 9.5.1-1(h).

The use of plastic materials in the plant is minimized through design and administrative controls. The storage of flammable liquids complies with the criteria specified in NFPA 30, "Flammable and Combustible Liquids Code," referenced in BTP CMEB 9.5-1 and RG 1.189.

Hydrogen lines in safety-related areas are designed to seismic Category I requirements. The design of the plant's hydrogen system complies with the criteria specified in NFPA 50A, "Standard for Gaseous Hydrogen Systems at Consumer Sites," referenced in BTP CMEB 9.5-1 and RG 1.189.

With the exception of the breathing air storage tanks for the MCR, the applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff finds that the applicant meets BTP CMEB 9.5-1, with this one exception. Therefore, this aspect of the AP1000 design is acceptable.

9.5.1.5.e Cable Construction (Regulatory Position C.5.e of BTP CMEB 9.5-1)

Cable trays, conduit, and other electrical raceways are constructed of noncombustible and metallic materials, in accordance with the criteria specified in BTP CMEB 9.5-1. Electrical raceways are only used for cables.

Safety-related cable trays located outside of containment are separated from redundant divisions and non-safety-related areas by 3-hour, fire-rated barriers. Cable trays containing safety-related cables, located inside containment, are enclosed in noncombustible steel or steel composite materials. Safety-related cable trays are provided with line-type heat detection and are designed to allow wetting with fire suppression water without causing electrical faults. With the exception of the containment, safety-related cable trays are accessible for manual firefighting. In fire zone 1100 AF 11300B, the applicant provided a manually actuated water spray system over the non-safety-related open cable trays in this zone.

Electrical cable is qualified in accordance with the criteria specified in IEEE Std 1202. Miscellaneous storage and piping for combustible liquids or gases are located so as not to present an exposure hazard to safety-related systems. In accordance with BTP CMEB 9.5-1, the applicant provided reasonable assurance that one division of the safety-related cables will remain free of fire damage. Therefore, the staff finds this aspect of the design to be acceptable.

9.5.1.5.f Ventilation (Regulatory Position C.5.f of BTP CMEB 9.5-1)

In accordance with BTP CMEB 9.5-1, the ventilation system is designed to allow smoke and other combustion products following a fire to be discharged to an area that will not affect safety-related equipment.

DCD Tier 2, Section 9A.3.1.1, discusses ventilation for the containment/shield building. Smoke control for this area consists of VFS containment isolation valves. If open, they are closed by operator action to control the spread of fire and smoke. After the fire, smoke is removed from the fire area by portable exhaust fans and flexible ductwork.

DCD Tier 2, Section 9A.3.1.2 and Table 9A-4 discuss smoke control for the NRCA portion of the auxiliary building, including a summary of the ventilation systems serving fire areas containing Class 1E components. This section also describes the approach to smoke control for fire areas in the NRCA portion of the auxiliary building that contain the main Class 1E electrical equipment rooms served by the VBS.

DCD Tier 2, Section 9A.3.1.3, discusses smoke control for the RCA portion of the auxiliary building. The VAS serves this fire area on a once-through basis. Smoke is removed from this fire area by using portable exhaust fans and flexible ductwork.

DCD Tier 2, Section 9A.3.2, discusses the smoke control features in the turbine building. The VTS uses roof-mounted exhaust ventilators to pull air through wall louvers. The smoke and heat vents and, if available, the roof-mounted exhaust ventilators, vent smoke to outside areas to prevent smoke migration. The dedicated smoke and heat vents provide additional assurance that excessive smoke and heat cannot build up at the turbine building ceiling, and are designed to conform to NFPA 204, "Standard for Smoke and Heat Venting."

DCD Tier 2, Section 9A.3.4, discusses annex building smoke control features. For the elevator shaft and elevator, smoke is removed using the wall exhaust fan or portable exhaust fans and flexible ductwork. Other areas within the annex building are exhausted using the VXS. In the ancillary DG room of the annex building, automatic suppression is provided. After a fire, smoke is removed from this area by using portable exhaust fans and flexible ductwork.

In the DG building, discussed in DCD Tier 2, Section 9A.3.6, smoke and heat ventilation capability is provided. Smoke control features for this area include manually turning on ventilation exhaust fans mounted on the roof over the fire area, or opening the roll-up door and personnel doors and utilizing portable exhaust fans.

The release of smoke and hot gases to the environment is monitored in accordance with the guidance specified in RG 1.101, *"Emergency Planning and Preparedness for Nuclear Power Plants."* The applicant evaluated the ventilation systems to ensure that inadvertent operation or single failures will not violate the RCAs of the plant.

The power supply and control for the ventilation systems are routed outside of the fire area served by the system. Air intakes for ventilation systems serving areas containing safety-related equipment are remotely located away from the exhaust air outlets and smoke vents of other fire areas.

The AP1000 design includes no safety-related ventilation systems; therefore, guidance related to engineered safety feature filters and gaseous suppression systems is not applicable to the AP1000.

The applicant evaluated the smoke control capability of the normal ventilation system against the criteria specified in NFPA 92A, "Recommended Practice for Smoke-Control Systems," including stair tower pressurization in the auxiliary building. Specifically, the applicant provided dedicated fans to maintain the minimum design pressure difference across the doors in stair towers S01 and S02, in accordance with the guidance specified in NFPA 92A. The staff finds this acceptable.

The staff determined that the applicant demonstrated that the ventilation system is designed to discharge smoke and other combustion products following a fire to an area that will not affect safety-related equipment, as specified in BTP CMEB 9.5-1. Therefore, the staff finds this aspect of the AP1000 design to be acceptable.

9.5.1.5.g Lighting and Communication (Regulatory Position C.5.g of BTP CMEB 9.5-1)

BTP CMEB 9.5-1 recommends that the design should include fixed, self-contained lighting units with individual 8-hour battery supplies. However, the AP1000 design utilizes alternate emergency lighting in the MCR and remote shutdown workstation that is powered by the

Class 1E dc and uninterruptible power supply (UPS). This has an expected duration of 72 hours in the event of a loss of normal ac power. A loss of the emergency lighting in either the MCR or the remote shutdown workstation will not result in a loss of the emergency lighting in the other area. In the event of a loss of the normal lighting, the emergency lighting in other plant areas is provided by 8-hour, battery-powered, fixed, self-contained units to provide safe ingress and egress of personnel and the operation of equipment following a fire. Portable battery-powered lighting is provided for emergency use by plant personnel. The staff finds this acceptable because the AP1000 design ensures lighting to areas vital to safe shutdown in the event of a fire. This is Deviation 9.5.1-6.

Fixed emergency communications are provided at selected locations, independent of the normal plant communications system.

The COL applicant is responsible for providing portable radio communication for use by the plant fire brigade. *This is COL Action Item 9.5.1-1(i).*

The applicant demonstrated that the emergency lighting and communications, available in the event of a fire, will provide a level of protection equivalent to that specified in BTP CMEB 9.5-1. Therefore, this aspect of the AP1000 design is acceptable.

9.5.1.6 <u>Fire Detection and Suppression (Regulatory Position C.6 of BTP CMEB 9.5-1)</u>

The COL applicant is responsible for ensuring that any deviations from the applicable NFPA codes and standards, in addition to those specified in the DCD, are incorporated into the final safety analysis report (FSAR) with appropriate technical justification. This is COL Action Item 9.5.1-5.

9.5.1.6.a Fire Detection (Regulatory Position C.6.a of BTP CMEB 9.5-1)

Fire detection systems designed and installed in accordance with the criteria specified in NFPA 72, "Protective Signaling Systems," are provided in all plant areas that contain or present a potential fire exposure to safety-related equipment. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1 and the staff agrees. Therefore, this aspect of the design is acceptable.

9.5.1.6.b Fire Protection Water Supply (Regulatory Position C.6.b of BTP CMEB 9.5-1)

The fire water supply system is designed in accordance with BTP CMEB 9.5-1 and the applicable NFPA standards. The AP1000 design includes an underground yard fire main loop, *separate from the sanitary or SWS, designed and installed in accordance with the criteria* specified in NFPA 24, "Installation of Private Fire Service Mains and Their Appurtenances." In addition, indicating isolation valves are provided to permit maintenance or repair of the fire main and outside hydrants without interrupting the water supply to both the primary and backup fire suppression capability in areas that contain or present an exposure to safety-related equipment. The applicant states that the AP1000 design is a single-unit plant; therefore, cross-connections at multiunit sites is not part of the AP1000 design.

Two redundant 100-percent capacity fire pumps (one diesel and one electric), designed and installed in accordance with the criteria specified in NFPA 20, "Centrifugal Fire Pumps," are provided. A motor-driven jockey pump is used to keep the fire water system full of water and pressurized, as required. Each pump and its driver and controls are separated from the remaining fire pumps by a 3-hour-rated fire wall. The fire pumps can be aligned through normally closed valves or through temporary connections to supply water for postaccident services. These include refilling of the PCS water supply tank or supplying the containment spray following a severe accident.

In addition, Section 7.2 of WCAP-15871 states that the fire water supply is based on the largest expected flow rate, but will not be less than 1135.62 kL (300,000 gallons). This flow rate is based on 1892.71 L/min (500 gpm) for manual hose streams plus the largest design demand of any sprinkler or fixed water supply, as determined by NFPA 13, "Installation of Sprinkler Systems," or NFPA 15, "Water Spray Fixed Systems for Fire Protection."

The outside manual hose installation is sufficient to provide an effective hose stream to any onsite location that could present a fire exposure hazard to structures containing safety-related equipment. Fire hydrants are installed approximately every 76.2 m (250 ft) on the yard main. Hose houses are provided in accordance with the criteria specified in NFPA 24. Threads compatible with the local fire department are provided on all hydrants, hose couplings, and standpipe risers.

Fire water is supplied from two separate fresh water storage tanks. The storage capacity of each tank is sufficient to maintain the design fire pump flow rate for at least 2 hours. Either tank can be automatically refilled within 8 hours. Freeze protection is provided as needed using electric immersion heaters. The primary fire water tank is dedicated to the FP system. The secondary fire water tank serves the raw water system, but contains water for use by the FP system and the containment spray system. The deviation from Regulatory Position C.6.b of BTP CMEB 9.5-1 provides adequate defense-in-depth and will not adversely affect the performance of the FP water supply. Therefore, it is acceptable. This is Deviation 9.5.1-10.

The fire water tanks are permanently connected to the suction piping of fire pumps and are arranged so that the pumps can take suction from either or both tanks. Piping between the fire water sources and the fire pumps complies with NFPA 20. A failure in one tank or its piping cannot cause both tanks to drain.

The standpipe system for areas containing equipment required for safe shutdown following an SSE is designed and supported so that it can withstand the effects of an SSE and still remain functional. The water supply for the seismic standpipe system comes from the PCS ancillary water storage tank and the safety-related PCS storage tank, as stated in DCD Tier 2, Section 9.5.1.2.1.5. These tanks are not designed in accordance with the criteria specified in NFPA 22, "Water Tanks for Private Fire Protection." This system normally operates independently of the rest of the FP system. Its volume of water is sufficient to supply two hose streams, each with a flow of 283.9 L/min (75 gpm), for 2 hours. This is Deviation 9.5.1-7. In the event that the PCS is unavailable or additional water is needed, the seismic standpipe system can be supplied from the fire main by manually opening the normally closed cross-connect valve from the plant fire main. On this basis, the staff concludes that the safety-related storage tanks and the manual opening of the cross-connect valve are acceptable. These are Deviations 9.5.1-7 and 9.5.1-8, respectively.

The PCS water recirculation pumps are not designed and installed in accordance with the criteria specified in NFPA 20. This deviation from the NFPA standards will not adversely affect the performance of the seismically qualified portions of the FP water supply system and, therefore, is acceptable. This is Deviation 9.5.1-9.

9.5.1.6.c Sprinkler and Standpipe Systems (Regulatory Position C.6.c of BTP CMEB 9.5-1)

Automatic sprinkler systems are provided in accordance with BTP CMEB 9.5-1 and are designed and installed in accordance with the criteria specified in NFPA 13, with an exception concerning individual fire department connections to each sprinkler system. Because the sprinkler systems are supplied by the plant's FP water supply, individual connections are not necessary. This is Deviation 9.5.1-11. The selection of automatic suppression systems for each plant area is based on the guidance of NFPA 804. Fixed automatic fire suppression is based on the results of the FP analysis. The staff concludes that the automatic sprinkler system design meets the guidance of BTP CMEB 9.5-1 and, with the exception of this deviation, is acceptable.

Standpipes for each building are designed and installed in accordance with the criteria specified in NFPA 14, "Installation of Standpipe and Hose Systems," for Class III service except for (1) the water supply to the standpipe inside containment is manually operated, and (2) the containment isolation valves controlling the water supply to the standpipes inside containment are not listed by an independent testing laboratory for FP service. The staff concludes that these deviations from the code will not adversely affect the performance of the hose station and standpipe system because these deviations will not prevent manual fire suppression activities inside containment. Therefore, these deviations are acceptable. These are Deviations 9.5.1-12 and 9.5.1-13.

9.5.1.6.d Halon Systems (Regulatory Position C.6.d of BTP CMEB 9.5-1)

Halon fire suppression systems are not used in the design of the AP1000; therefore, the guidance specified in BTP CMEB 9.5-1 is not applicable.

9.5.1.6.e Carbon Dioxide Systems (Regulatory Position C.6.e of BTP CMEB 9.5-1)

Carbon dioxide fire suppression systems are not used in the design of the AP1000. Therefore, the guidance specified in BTP CMEB 9.5-1 is not applicable.

9.5.1.6.f Portable Fire Extinguishers (Regulatory Position C.6.f of BTP CMEB 9.5-1)

Portable fire extinguishers are provided in accordance with the criteria specified in NFPA 10, "Portable Fire Extinguishers." They are provided throughout the plant and are readily accessible for use in high radiation areas. However, they are not located within those areas unless the FP analysis indicates that a specific requirement exists. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the portable fire extinguishers meet BTP CMEB 9.5-1 and, therefore, are acceptable.

9.5.1.7 Specific Plant Areas (Regulatory Position C.7 of BTP CMEB 9.5-1)

9.5.1.7.a Primary and Secondary Containment (Regulatory Position C.7.a of BTP CMEB 9.5-1)

Fire protection for the containment is provided as specified in the applicant's fire hazard analysis. A lube oil collection system for the RCPs is not required because the four canned RCPs use water for lubrication and do not contain oil. Operation of the FP suppression systems located inside containment will not compromise the integrity of the containment or other safety-related systems. Fire detection is provided in the primary containment and annulus for each fire hazard. DCD Tier 2, Appendix 9A, identifies the type of detection used and the location of the detectors most suitable for the specific fire hazards. Manual hose stations are provided in the primary containment, as identified in Appendix 9A. Redundant divisions of safety-related cables located in the middle annulus are separated by 3-hour fire barriers. Division B and D cables are located in the upper annulus, and Division A and C cables are located in the lower annulus.

The staff concludes that the applicant provided adequate FP inside primary containment to provide reasonable assurance that one division of safe-shutdown equipment and cables will remain free of fire damage, in accordance with NUREG-1242. As stated in Appendix 9A to DCD Tier 2, Section 9A.3.1.1, the safe-shutdown components located inside the containment are primarily components of the PXS, the RCS, the steam generator system (SGS), and containment isolation. Hose stations for manual suppression are provided inside containment, however, because of the potential hazard associated with personnel entry into containment during a plant transient, the response of the plant fire brigade may be significantly delayed. Therefore, the staff does not consider any credit for manual suppression of fires inside containment during power operations to be acceptable. The applicant located a manual (operated from the MCR) water spray system in fire zone 1100 AF 11300B over the exposed cable trays. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1, and the staff agrees that fire protection for the containment meets BTP CMEB 9.5-1. The staff finds this acceptable.

The COL applicant is responsible for fire protection inside containment during refueling and maintenance. This is COL Action Item 9.5.1-1(j).

9.5.1.7.b Control Room Complex (Regulatory Position C.7.b of BTP CMEB 9.5-1)

The MCR complex is noted in Appendix 9A to DCD Tier 2 as fire zone 1242 AF 12401A. This zone is separated from the other plant areas by 3-hour-rated fire barriers. The ceiling acts as a barrier to fires in the room above the MCR. Fire detection is provided in the general area and subfloor areas. Manual hose stations and portable fire extinguishers are provided for fire suppression. Smoke removal is provided by the nonradioactive ventilation system. Breathing apparatus is provided for control room personnel. The above provisions are in accordance with BTP CMEB 9.5-1.

Automatic suppression is not provided in the control room or peripheral rooms in this fire area. Fire detection is not provided in the cabinets or consoles. These omissions are not consistent with BTP CMEB 9.5-1. However, these deviations are acceptable because the control room is continuously occupied, the area fire hazard is low, manual suppression capability is available, and the remote shutdown workstation is located in a separate fire area. These are Deviations 9.5.1-14 and 9.4.1-15.

The staff concludes that the deviations from the guidance specified in BTP CMEB 9.5-1 do not adversely affect safety and, therefore, are acceptable. With the exception of these deviations, the MCR FP meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.7.c Cable Spreading Room (Regulatory Position C.7.c of BTP CMEB 9.5-1)

There are no cable spreading rooms in the AP1000. Therefore, the guidance specified in BTP CMEB 9.5-1 is not applicable.

9.5.1.7.d Plant Computer Rooms (Regulatory Position C.7.d of BTP CMEB 9.5-1)

There are no computers performing safety-related functions in the MCR complex. Non-safety-related computers outside the MCR are separated from safety-related areas by 3-hour fire barriers. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design in the plant computer rooms meets BTP CMEB 9.5-1, and finds this acceptable.

9.5.1.7.e Switchgear Rooms (Regulatory Position C.7.e of BTP CMEB 9.5-1)

The electrical equipment and penetration rooms associated with each safety-related division are separated from other plant areas and from redundant divisions by 3-hour, fire-rated barriers. Automatic fire detection, portable fire extinguishers, and manual hose stations are provided. Floor drains are provided for the removal of firefighting water. Smoke removal using the nuclear island nonradioactive ventilation system or portable fans and ductwork is provided for these areas. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design of the switchgear rooms meets BTP CMEB 9.5-1 and finds this acceptable.

9.5.1.7.f Remote Safety-Related Panels (Regulatory Position C.7.f of BTP CMEB 9.5-1)

Safety-related panels outside of the control room are separated from other plant areas by 3-hour fire barriers. Automatic fire detection, portable fire extinguishers, and manual hose stations are provided. Remote shutdown panels located in the remote shutdown workstation can be electrically isolated from the MCR by a transfer switch. Combustible materials in these areas will be controlled and limited to those required for operation. The COL applicant is responsible for controlling combustible materials. This is COL Action Item 9.5.1-1(k).

The applicant identified no deviations from the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design of the safety-related panels outside of the control room meets BTP CMEB 9.5-1 and finds this acceptable.

9.5.1.7.g Safety-Related Battery Rooms (Regulatory Position C.7.g of BTP CMEB 9.5-1)

Safety-related battery rooms are separated from each other and from other plant areas by 3-hour fire-rated barriers. Automatic fire detection is provided in the battery rooms. Portable extinguishers and hose stations are readily available outside the battery rooms. Ventilation systems are capable of maintaining the hydrogen concentration in the battery rooms below 2 percent. A loss of the battery room ventilation system alarms in the MCR. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design of the safety-related battery rooms meets BTP CMEB 9.5-1 and finds it acceptable.

9.5.1.7.h Turbine Building (Regulatory Position C.7.h of BTP CMEB 9.5-1)

DCD Tier 2, Section 9A.3.2, states that a fire in the turbine building areas does not affect the plant's safe-shutdown capability. Fire areas located in the turbine building are separated from adjacent structures containing safety-related equipment by 3-hour-rated fire barriers. The fire barriers are designed to maintain structural integrity in the event of a collapse of the turbine building. Openings and penetrations are minimized and are not located in proximity to the turbine lube oil system or generator hydrogen cooling system. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design of the turbine building areas meets BTP CMEB 9.5-1 and finds it acceptable.

9.5.1.7.i Diesel Generators

9.5.1.7.j Diesel Fuel Storage (Regulatory Positions C.7.i and C.7.j of BTP CMEB 9.5-1)

Portable extinguishers and manual hose stations are readily available outside the fuel storage area. Drainage for firefighting water and a means for manual venting of smoke is provided.

Each DG day tank has a total capacity of 5678 L (1500 gallons). Separate 3-hour enclosures and automatic suppression are provided. The tanks are located more then 15 m (50 ft) from buildings containing safety-related equipment. The fuel supply for the ancillary DGs is not separated from the diesels by a barrier. The ancillary diesels and the tank are separated from the rest of the plant by an enclosure with a 3-hour fire rating.

On the basis of the above information, the staff concludes that the deviations identified by the applicant do not adversely affect safety and, therefore, are acceptable.

The standby DGs are located in a separate structure, remote from safety-related areas. The standby DGs are separated from each other by 3-hour fire barriers. The ancillary DGs are located in the same fire area, but are separated from the other plant areas containing safety-related equipment by 3-hour fire barriers. However, they are not separated from one another by 3-hour fire barriers. This lack of 3-hour fire barrier separation between the ancillary DGs does not adversely affect safety because the ancillary DGs are not safety-related and their failure will not adversely affect safe shutdown. Therefore, the staff finds this deviation from Regulatory Positions C.7.i and C.7.j of BTP CMEB 9.5-1 to be acceptable. This is Deviation 9.5.1-16.

Automatic fire suppression is provided in the DG and fuel storage rooms and is designed to actuate during diesel operation without affecting the diesel. Automatic detection is provided in the DG service modules only. The dry pipe sprinklers provide detection in the DG and fuel storage rooms. This deviation from Regulatory Positions C.7.i and C.7.j of BTP CMEB 9.5-1 does not adversely affect safety because the standby DGs are not safety-related and their failure does not adversely affect safe shutdown. Therefore, this deviation is acceptable. This is Deviation 9.5.1-17.

9.5.1.7.k Safety-Related Pumps (Regulatory Position C.7.k of BTP CMEB 9.5-1)

The design of the AP1000 does not require safety-related pumps for safe shutdown following a fire. Therefore, the guidance specified in BTP CMEB 9.5-1 is not applicable.

9.5.1.7.l New Fuel Storage Area (Regulatory Position C.7.l of BTP CMEB 9.5-1)

The new fuel storage pit includes automatic fire detection, hose stations, and portable extinguishers. Automatic suppression is not provided in the new fuel storage pit. Floor drains are provided to prevent the accumulation of water that could result in an inadvertent criticality. The new fuel storage pit is located in the same fire area (1200 AF 02) as the rail car bay/filter storage area. The rail car bay/filter storage area is provided with automatic suppression. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design for the new fuel storage area meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.7.m Spent Fuel Pool Area (Regulatory Position C.7.m of BTP CMEB 9.5-1)

The fuel-handling area includes automatic fire detection, hose stations, and portable extinguishers. Automatic suppression is not provided in the new fuel storage pit. The fuel-handling area is located in the same fire area (1200 AF 02) as the rail car bay/filter storage area. The rail car bay/filter storage area has automatic suppression. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design for the SFP area meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.7.n Radwaste and Decontamination (Regulatory Position C.7.n of BTP CMEB 9.5-1)

The radwaste building is separated from the other plant areas containing safety-related equipment by 3-hour, fire-rated barriers. A dedicated ventilation system is provided for the radwaste building. Floor drains are sized to handle water flow from the fixed automatic FP systems without a significant accumulation of water in the fire area. Curbed areas within the radwaste building have sufficient capacity to retain FP water, thus preventing an unmonitored release to the environment.

Automatic fire suppression is provided in the mobile systems facility, waste accumulation room, and packaged waste storage room. Fire detection and hose stations are located throughout the radwaste building.

The cask washdown pit and the waste disposal container area are located in the same fire area (1200 AF 02) as the rail car bay/filter storage area. The rail car bay/filter storage area is provided with automatic suppression. As described above, the applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design for the radwaste and decontamination areas meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.7.o Safety-Related Water Tanks (Regulatory Position C.7.o of BTP CMEB 9.5-1)

The CMTs, IRWST, and PCS tanks are not susceptible to damage from an exposure fire. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design for the safety-related water tanks meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.7.p Records Storage Area (Regulatory Position C.7.p of BTP CMEB 9.5-1)

Records storage areas are located and protected so that a fire in these areas will not affect safety-related systems or equipment. The applicant identified no exceptions to the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design for the records storage area meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.7.q Cooling Towers (Regulatory Position C.7.q of BTP CMEB 9.5-1)

The cooling towers are not used as the ultimate heat sink or for FP purposes; therefore, the guidance specified in BTP CMEB 9.5-1 is not applicable. The COL applicant is responsible for fire protection for the cooling towers. This is COL Action Item 9.5.1-1(l).

9.5.1.7.r Miscellaneous Areas (Regulatory Position C.7.r of BTP CMEB 9.5-1)

Miscellaneous areas, such as shops, warehouses, auxiliary boiler rooms, fuel oil tanks, and flammable and combustible liquid storage tanks, are located and protected so that a fire, or the effects of a fire, will not affect any safety-related equipment. These areas are outside of the containment, which is separated from the other plant areas by a 3-hour fire barrier. The applicant identified no deviations from the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design for these areas meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.8 <u>Special Protection Guidelines (Regulatory Position C.8 of BTP CMEB 9.5-1)</u>

9.5.1.8.a Storage of Oxygen-Acetylene Fuel Gases (Regulatory Position C.8.a of BTP CMEB 9.5-1)

The COL applicant is responsible for the proper storage of welding gas cylinders. This is COL Action Item 9.5.1-1(m).

9.5.1.8.b Storage Areas for Ion Exchange Resins (Regulatory Position C.8.b of BTP CMEB 9.5-1)

The COL applicant is responsible for the proper storage of ion exchange resins. This is COL Action Item 9.5.1-1(n).

9.5.1.8.c Hazardous Chemicals (Regulatory Position C.8.c of BTP CMEB 9.5-1)

The COL applicant is responsible for the proper storage of hazardous chemicals. This is COL Action Item 9.5.1-1(o).

9.5.1.8.d Materials Containing Radioactivity (Regulatory Position C.8.d of BTP CMEB 9.5-1)

Materials that collect and contain radioactivity, such as spent resins, charcoal filters, and HEPA filters, are stored in closed metal containers that are located in areas free from ignition sources or combustibles. The applicant identified no deviations from the guidance specified in BTP CMEB 9.5-1. The staff agrees that the FP design associated with the storage of these materials meets BTP CMEB 9.5-1 and, therefore, is acceptable.

9.5.1.9 Evaluation of Fire Protection Open Items and COL Action Items

DSER Open Item 9.5.1-1

Personnel access and egress routes are provided for each fire area. Stairwells outside containment, serving as access or egress routes, are enclosed in gypsum towers, with a minimum fire resistance rating of 2 hours. The stairwells are equipped with self-closing doors, with a fire resistance rating of 1.5 hours. In NUREG-1512, the NRC staff had previously granted Deviation 9.5.1-2 allowing the use of gypsum stair towers in lieu of concrete or masonry in the AP600 design on the basis that there were no missile hazards in the vicinity of the subject stairwells.

Following the events of September 11, 2001, the Federal Emergency Management Agency (FEMA) issued FEMA 403, "World Trade Center Building Performance Study: Data Collection, Preliminary Observations and Recommendations," dated May 2002. Based on the performance of the gypsum stairwell enclosures in the World Trade Center following the aircraft impacts, Section 8.2.2.1 of this FEMA report recommends the use of impact-resistant enclosures around egress paths, such as stairwells.

In light of this information, the staff has reconsidered its previous acceptance of gypsum stairwell enclosures in lieu of the concrete or masonry enclosure specified by BTP CMEB 9.5-1. In RAI 280.001, the staff requested an evaluation of the stairwells that have not been enclosed in masonry or concrete towers with a minimum fire rating of 2 hours, as specified in Regulatory Position C.5.a.6. of CMEB 9.5.1. In addition, the staff requested that the applicant provide a revision to the DCD to incorporate the original BTP guidance for the use of concrete or masonry enclosures. The staff reviewed the applicant's revised response and determined that the resolution of this issue is inadequate for the following three reasons:

(1) In place of the gypsum, the applicant proposed installation of a fire barrier material noted as a "concrete/steel composite material." This material would be installed throughout the auxiliary, turbine, and annex buildings to enclose stairwells, as shown in the revision to Item 55 in DCD Tier 2, Table 9.5.1-1. The applicant did not demonstrate that the as-built configuration would meet the applicable regulation (GDC 3, "Fire Protection") and the applicable guidance (BTP CMBE 9.5-1). The use of the concrete/steel composite material is inadequate for the following reasons:

   - The applicant did not submit documentation or test reports to verify the rating of the fire barrier. The documentation should demonstrate that this composite material withstood a standard fire exposure as specified in NFPA 251, "Tests of Fire Endurance of Building Construction and Materials," also known as ASTM E119, "Standard Test Method of Fire Tests of Building Construction and

Materials." For additional guidance, see Section 3.1.6 of GL 86-10, "Implementation of Fire Protection Requirements."

– Section 3.2 of GL 86-10 provides additional guidance on fire barrier qualification. It does not appear from the information submitted that the applicant demonstrated that the composite barrier material provided an equivalent level of safety to concrete or masonry, as discussed in GL 86-10. For example, the applicant's RAI response did not discuss the following information pertaining to the fire barrier material:

  - deviations between the field installation and the tested configuration
  - ASTM E-119 acceptance criteria (hose stream tests results, temperatures on the unexposed side of the barrier, no passage of flames or ignition to unexposed side, etc.)

On this basis, the staff did not agree that the applicant demonstrated that the performance of the composite steel/concrete barrier provides a level of safety equivalent to that provided by the guidelines in BTP CMEB 9.5-1.

(2) The applicant failed to provide adequate protection for stairwells S03 and S06 in accordance with BTP CMEB 9.5-1.

BTP CMEB 9.5-1 recommends that stairwells outside of the primary containment, which serve as escape routes, access for firefighting, or access routes to areas containing equipment necessary for safe shutdown, be enclosed in concrete or masonry. In the auxiliary building, stairwell S03 provides an entry point to stairwell S06 (PCS valve room). DCD Tier 2, Section 6.2.2.2.2, identifies the PCS as a safety-related system. Stairwells S03 and S06 are located aboveground, have no adjacent structures to provide a shield or additional protection for either stair tower, and have no alternate stairwells for personnel to travel in the event that either stairwell S03 or stairwell S06 is impacted by an external missile. The applicant revised Item 55 in DCD Tier 2, Table 9.5.1-1, to state that, "There is little need for access to this room (PCS Valve Room). Protection of these stairwells by concrete or masonry walls is not required." The staff disagrees with this statement.

In the event an external missile impacts either stairwell, plant personnel located in the plant areas served by these stairwells would not have an alternate escape route to compensate for the lack of structural protection in stairwells S03 and S06. These stairwells are the primary escape routes and have not been protected in accordance with BTP CMEB 9.5-1.

(3) For those stairwells where concrete is partially installed on the exterior walls, the applicant stated that the thickness of the concrete varies from between 0.61 to 0.91 m (2 to 3 ft). For installation of the composite steel/concrete barrier on the interior walls of these stairwells, the thickness was noted as 20.3 cm (8 in.). The applicant did not present an analysis to demonstrate, from a structural design, that 20.3 cm (8 in.) of the composite material would provide a level of structural integrity equivalent to a 0.61 to 0.91 m (2 to 3 ft) thickness of concrete. On this basis, the staff does not agree that the

applicant has demonstrated that the performance of the composite steel/concrete barrier will provide a level of safety equivalent to that provided by the guidelines of BTP CMEB 9.5-1.

This was identified as Open item 9.5.1-1 in the DSER.

By letter dated July 3, 2003, the applicant provided a response to Open Item 9.5.1-1, concerning its proposed fire barrier material, which is a concrete/steel composite material manufactured by DuraSystem Barriers, Inc., for the stairwells of the auxiliary, turbine, and annex buildings. The applicant proposed to use this material in lieu of concrete or masonry towers having a minimum fire rating of 2 hours, as specified in Regulatory Position C.5.a.6 of BTP CMEB 9.5.1. The applicant stated in its response that, "the fire resistance test of the base design concrete/steel composite material is documented in Underwriters Laboratories, Inc., File R11164-1, Project 84NK1877 of October 26, 1984. The report states that the test was conducted in accordance with Standard UL 263 (ASTM E119, NFPA No. 251 and ANSI A2.1). This UL listing responds to Section 3.1.6 of GL 86-10 and a copy of the test report is available for NRC audit at Westinghouse and DuraSystem offices...."

On August 22, 2003, the staff visited the Westinghouse office in Rockville, Maryland, to audit the fire resistance test, File R11164-1, Project 84NK1877, of October 26, 1984. The staff noted that the fire test was performed according to the UL Test Assembly Design No. U031, Assembly Rating for 3 hours for Nonbearing Wall, with a panel thickness of 9.5 mm (3/8 in.). The test was conducted in accordance with ASTM E119 requirements and included hose stream tests, temperature measurements on the unexposed side, and inspection for passage of flame or ignition to the unexposed side. The test was rated for UL Test Assembly Design No. U031 for 3 hours. The staff agrees with the test results and the details of the documentation. The staff also believes that this rating is adequate and acceptable. The Regulatory Position C.5.a.6 of BTP CMEB 9.5.1 requires a minimum fire rating of 2 hours for concrete or masonry construction.

The staff reviewed the applicant's response to Open Item 9.5.1-1 and required responses to the following issues to complete its review:

(a) Provide the fire resistance rating of stairwell doors installed throughout the auxiliary, turbine, and annex buildings.

(b) Specify what UL design is used in stairwells throughout the auxiliary, turbine, and annex buildings in all drawings. The fire resistance test File R11164-1, Project 84NK1877 of October 26, 1984, refers to UL Test Assembly Design No. U031 for 3 hours.

(c) On DSER OI 9.5.1-1, page 3, the applicant stated that, "Stairwells S03 and S06 provide access to the PCS valve room. As noted in the Open Item, the PCS valve room does contain safety-related equipment. Access is not required to any of this equipment to respond to an accident...."

Clarify why access is not required to the PCS valve room, although this room contains safety-related equipment, and how the fire brigade will approach the PCS valve room for manual firefighting; safe personnel access routes and escape routes should be provided for each fire area. Stairwells outside the primary containment which serve as escape

> routes, access routes for firefighting, or access routes to areas containing equipment necessary for safe shutdown should be enclosed in masonry or concrete towers with a minimum fire rating of 2 hours and include self-closing Class B fire doors.

In response to the staff's request for clarifying information, by letter dated October 21, 2003, the applicant provided Revision 1 to Open Item 9.5.1-1. In its response to Item a above, the applicant stated that Section 9.5.1.2.1.1, "Plant Fire Prevention and Control Features, Architectural and Structural Features," of the AP1000 DCD states that the stairwell openings are protected by approved automatic or self-closing doors having a fire rating of 1.5 hours. The staff verified that in accordance with NFPA 80, "Fire Doors and Windows," 1999 Edition, and NFPA 252, "Standard Methods of Fire Tests of Door Assemblies," 2003 Edition, the fire barriers having a required fire resistance rating of 2 hours shall include only fire door assemblies having a minimum fire resistance rating of 1.5 hours. The staff finds this acceptable; the applicant meets the guidelines of BTP CMEB 9.5-1. Therefore, DSER Open Item 9.5.1-1, Item a, is resolved.

In its October 21, 2003, letter, the applicant did not provide the type of 2-hour wall design assembly, and associated fire resistance test results, to be installed using concrete/steel composite material. Rather, in response to Item b, above, the applicant provided a fire resistance test File R11164-1, Project 84NK1877 of October 26, 1984, that refers to UL Test Assembly Design No. U031 for 3 hours. The applicant did not address if it intends to utilize the 3-hour fire resistance test. In DCD Tier 2, Section 9.5.1.8 Westinghouse states that the COL applicant will address the process for identifying deviations between the as-built installation of fire barriers and their tested configurations. This is COL Action Item 9.5.1-6. Westinghouse revised DCD Tier 2, Section 9.5.1.8 to include a combined license item that states "[t]he Combined License applicant will provide 2-hour fire resistance test data in accordance with ASTM E-119 and NFPA 251 for the composite material selected for stairwell fire barriers." This is COL Action Item 9.5.1-7.

The staff will review the COL applicant's stairwell fire barriers fire resistance performance test results to determine that they perform in an equivalent manner to maintain the integrity of the enclosed stairwell in accordance Regulatory Position C.5.a.6 of BTP CMEB 9.5.1.

Therefore, DSER Open Item 9.5.1-1, Item b, is resolved.

In its October 21, 2003, letter, the applicant stated that:

> AP1000 Design Control Document, Appendix 9A, Table 9A-2 (Sheet 7 of 14) identifies the safe-shutdown components in the PCS valve room (Room 12701, Fire Area 1000 AF 01, Fire Zone 1270 AF 12701). The components in this room consist of six (2 air-operated and 4 motor-operated valves) Passive Containment Cooling Water Storage Tank (PCCWST) isolation valves and five PCCWST flow/level instruments. In the unlikely event that a fire occurred in Room 12701 to the extent that these components were rendered inoperable, the ability to achieve safe shutdown would not be compromised.
>
> Normal shutdown operations may be required in the event that a fire were to significantly damage the safe-shutdown components located in Room 12701.

> Normal shutdown operations do not require the actuation of the PCS valves located in this room.
>
> In the event of a design-basis accident the three, normally closed, PCCWST isolation valves (two air operated valves and one motor operated valve) located in Room 12701 could receive an automatic signal to open. Access to the PCS valve room is not required for their operation.
>
> There is very little combustible material in the PCS valve room fire area. In the unlikely event of a fire, the fire brigade would approach the PCS valve room (Room 12701, Fire Zone 1270 AF, Fire Area 1000 AF 01) by using the Stairwell S03 of the adjacent elevator that is attached to the outside wall on the shield building. The fire bridge would egress from Stairwell S03 (Fire Area 120A AF 02) at the El. 264'-6" platform (Fire Area 1270 AF, Fire Area 1000 AF 01). They would proceed up the included stair S06 to the PCS valve room (Room 12701) located on El. 286'-6". From this position they could utilize fire extinguishers for manual fire fighting.

The staff reviewed the applicant's response to Item c and found it unacceptable. The staff believes that access is required to the PCS valve room (Room 12701) because it contains safety-related equipment for safe shutdown. BTP CMEB 9.5.1, Regulatory Position C.6.c.4, requires that an, "interior manual hose should be able to reach any location that contains, or could present a fire exposure hazard to, safety-related equipment with at least one hose stream...." The staff believes that for manual firefighting, fire extinguishers are not always effective, and often water hose streams are required for effective firefighting.

To resolve DSER Open Item 9.5.1-1, Item c, the staff issued RAIs to evaluate the effectiveness of fire extinguishers for suppression cable and oil fire in the PCS valve room. The RAIs requested information concerning the quantities of in situ combustibles, the type of transient combustible materials planned to be introduced during the maintenance work, and the type of portable fire extinguishers that would be provided in the PCS valve room.

In a letter dated December 22, 2003, the applicant provided the following response:

> The type of portable fire extinguishers that would be provided in the PCS valve room would be Type ABC (dry chemical) with a capacity of 20 pounds. A total of four fire extinguishers will be provided in the PCS valve room with two fire extinguishers located at El. 264'-6" lower level and two fire extinguishers located at the EL. 286'-6" upper level.
>
> In the unlikely event of a fire, the fire brigade would approach the PCS valve room (Room 12701, Fire Zone 1270 AF, Fire Area 1000 AF 01) by using the Stairwell S03 or the adjacent elevator that is attached to the outside wall on the shield building. The fire brigade would egress from Stairwell S03 (Fire Area 1204 AF 02) into the lower level of the PCS valve room (Room 12701) at the El. 264'-6" platform (Fire Zone 1270 AF, Fire Area 1000 AF 01). Portable fire extinguishers are provided at this lower level for manual fire fighting. The fire brigade would proceed up the inclined stairs S06 to upper level of the PCS valve

> room (Room 12701) located on El. 286'-6". Additional portable fire extinguishers are provided at this upper level for manual fire fighting.

The staff reviewed the applicant's response to Item c and expressed a concern that the dry chemical portable fire extinguishers may not be adequate to completely extinguish deep-seated electrical cable fires. The staff referred to NRC Information Notice 2002-27, which addresses the extinguishment practice and discusses the need for special consideration to be given to the means of fire extinguishment and the associated effects.

During a conference call on January 23, 2004, the applicant agreed to issue a revision to Open Item 9.5.1-1, Item c, which included the following:

> In the unlikely event of a fire, the fire brigade would approach the PCS valve room (Room 12701, Fire Zone 1270 AF, Fire Area 1000 AF 01) by using the Stairwell S03 or the adjacent elevator that is attached to the outside wall on the shield building. The fire brigade would egress from Stairwell S03 (Fire Area 1204 AF 02) into the lower level of the PCS valve room (Room 12701) at the El. 264'-6" platform (Fire Zone 1270 AF, Fire Area 1000 AF 01). Two types of portable fire extinguishers (a dry chemical and water fire extinguisher) are provided at this lower level for manual fire fighting. The fire brigade would proceed up the inclined stairs S06 to upper level of the PCS valve room (Room 12701) located on El. 286'-6". Two types of portable fire extinguishers (a dry chemical and a water fire extinguisher) are also provided at this upper level for manual fire fighting.

The staff reviewed the applicant's commitment to provide water fire extinguishers along with dry chemical extinguishers. The staff found it acceptable. Operating experience with major electrical cable fires shows that water will promptly extinguish such fires. Therefore, Open Item 9.5.1-1 is resolved.

<u>DSER Open Item 9.5.1-2</u>

In RAI 280.011, the NRC staff raised a concern that 41percent of the total fire-induced core damage frequency (CDF) is assigned to containment. The containment fire is a large contributor to CDF, and areas in containment exist where redundant safe-shutdown components required following a fire have not been separated by complete fire barriers. Therefore, the NRC staff requested that the applicant perform a mathematical fire model in accordance with NFPA 805, "Performance-Based Standard for Fire Protection for Light-Water Reactor Electric Generating Plants." The fire model should demonstrate that a fire would be confined to the zone of origin so that redundant components remain free of fire damage. The applicant selected the fire-induced vulnerability evaluation (FIVE) methodology found in EPRI TR-100370, "Fire-Induced Vulnerability Evaluation (FIVE) Methodology," issued April 1992. This is not a mathematical fire model. FIVE was approved by the NRC in the early 1990s primarily as a tool to provide a qualitative assessment of fire risk for the individual plant examination of external events (IPEEE) to perform fire probabilistic risk assessments (PRAs). The FIVE methodology is limited in that large open areas, such as those in containment, are not capable of being realistically modeled. Therefore, the NRC staff expressed concern about the appropriateness of FIVE methodology for modeling fires within containment.

The applicant responded to the RAI by stating that NFPA 805 permits the use of the FIVE methodology. The staff responded that Appendix C, Section C.2.2., "Fire Model Features and Limitations" of NFPA 805 specifically states that the limitations of each fire model should be taken into consideration, so as to produce reliable results that will be useful in decisionmaking. This section specifically states that, "Some models may not be appropriate for certain conditions and can produce erroneous results if applied incorrectly." Appendix C, Table C.2.2.(b), of NFPA 805 enables the user to select the appropriate model for a particular fire area, so as to obtain useful estimates to best approximate the conditions within an enclosure as a result of an internal fire. In addition, NFPA 805 states that the fire model shall be acceptable by the authority having jurisdiction (AHJ). In this case, the AHJ is the NRC. The NRC has not accepted the use of the FIVE methodology outside of the IPEEEs. The staff does not agree that the use of FIVE is an appropriate choice to model a fire within containment. This was identified as Open Item 9.5.1-2 in the DSER.

By letter dated August 13, 2003, the applicant provided the following response to Open Item 9.5.1-2, Revision 1, concerning the use of the FIVE methodology for fire hazard analysis:

> Westinghouse believes that our licensing submittals related to fire protection have satisfied the written regulatory requirements and guidance for Design Certification. Westinghouse has provided a fire hazards analysis in DCD Appendix 9A that demonstrates that the AP1000 complies with or requests exemptions from the requirements of BTP CMEB 9.5-1. AP1000 has used a deterministic-based approach for the fire evaluation described in Chapter 9 and Appendix 9A of the AP1000 Design Control Document (DCD). Consistent with Chapter 2 and Figure 2.2 (Methodology) of NFPA 805, AP1000 has chosen this deterministic approach to justify its compliance with the fire protection requirements of 10 CFR Part 50 and 10 CFR Part 52. NFPA 805 clearly indicates that the designer may use either the deterministic or the probabilistic method for fire evaluation. Since this hazards evaluation was deterministic, it "involves implied, but unquantified, elements of probability in the selection of specific accidents to be analyzed as design-basis event" (see NFPA 805, Section 1.6.11). The FIVE methodology was not used in the fire hazards analysis documented in AP1000 Appendix 9A to justify compliance with regulatory fire protection requirements.
>
> In addition, to comply with an NRC request to have an AP1000-specific PRA, Westinghouse has performed a fire PRA as part of the overall AP1000 PRA. 10 CFR Part 52 requires an applicant to submit a plant-specific PRA, although it does not specifically require a fire PRA. The results of the fire PRA have shown that AP1000 plant risk due to fire is extremely low. The AP1000 PRA methodology included using the FIVE methodology inside containment at NRC's request. The FIVE methodology is an acceptable methodology for probabilistic analysis in accordance with NFPA 805. The Revision 1 response to RAI 280.011 and the current revision of the AP1000 Probabilistic Risk Assessment report describe the method used for AP1000. They also describe that the method used may be overly conservative and that additional safety-related function or component based assessments were performed to ensure the design has a very low risk from fire in containment affecting its safety. Although fires in containment represent the largest percentage contributor to CDF, the overall

CDF itself is acceptably small. No further refinement of the PRA is needed. In many areas of the PRA, more detailed or sophisticated analysis may lead to improvement in the PRA results. It is acceptable to conservatively simplify the PRA analysis.

Westinghouse concludes that AP1000 has met the applicable fire-related regulations, and that no additional fire analysis is required.

The staff reviewed the applicant's response and found it to be acceptable. The FIVE methodology, documented in Appendix 9A to DCD Tier 2, was not used in the fire hazards analysis to justify compliance with the regulatory requirements. Further, the applicant used a deterministic approach based on NFPA 805, Chapter 2, to establish AP1000 fire protection requirements.

The staff finds that the information provided by the applicant satisfies the staff's concern. Therefore, DSER Open Item 9.5.1-2 is resolved.

APPLICABLE NATIONAL FIRE PROTECTION ASSOCIATION CODES, STANDARDS, AND RECOMMENDED PRACTICES

NFPA 10, "Portable Fire Extinguishers"
NFPA 13, "Installation of Sprinkler Systems"
NFPA 14, "Installation of Standpipe and Hose Systems"
NFPA 15, "Water Spray Fixed Systems for Fire Protection"
NFPA 20, "Centrifugal Fire Pumps"
NFPA 22, "Water Tanks for Private Fire Protection"
NFPA 24, "Installation of Private Fire Service Mains and Their Appurtenances"
NFPA 30, "Flammable and Combustible Liquids Code"
NFPA 50A, "Gaseous Hydrogen Systems at Consumer Sites"
NFPA 72, "Protective Signaling Systems"
NFPA 80, "Fire Doors and Windows"
NFPA 90A, "Installation of Air Conditioning and Ventilation Systems"
NFPA 92A, "Recommended Practice for Smoke-Control Systems"
NFPA 204, "Smoke and Heat Venting"
NFPA 251, "Tests of Fire Endurance of Building Construction and Materials"
NFPA 804, "Fire Protection for Advanced Light Water Reactor Electric Generating Plants"
NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants"

SUMMARY OF APPROVED DEVIATIONS AND COL ACTION ITEMS FOR THE AP1000

I. Approved Deviations

9.5.1-1 Single failure of primary and backup fire suppression inside containment

9.5.1-2 Cable insulation in concealed spaces of the control room, technical support center, and remote shutdown workstation

9.5.1-3 Definition of safe shutdown for the AP600 and the AP1000

9.5.1-4	Achievement of cold shutdown in 72 hours
9.5.1-5	Breathing air storage tanks located in the auxiliary building
9.5.1-6	Self-contained emergency lighting in the control room and remote shutdown workstation
9.5.1-7	Compliance of PCS tanks with NFPA 22
9.5.1-8	Manual connection between seismic standpipe and yard loop
9.5.1-9	Compliance of PCS recirculation pumps with NFPA 20
9.5.1-10	Dual use of secondary fire water tank
9.5.1-11	Fire department connections to the sprinkler systems
9.5.1-12	Manual operation of standpipe inside containment
9.5.1-13	Containment isolation valves not listed for fire protection service
9.5.1-14	Automatic suppression of peripheral rooms in control room complex
9.5.1-15	Fire detection in MCR cabinets and consoles
9.5.1-16	Fire separation of ancillary diesels
9.5.1-17	Fire detection in DG room (automatic detection not provided in the DG and fuel storage rooms)

II. COL Action Items

9.5.1-1(a)	Fire protection program
9.5.1-1(b)	Implementation of fire protection program
9.5.1-1(c)	Administrative controls
9.5.1-1(d)	Fire brigade
9.5.1-1(e)	Quality assurance program
9.5.1-1(f)	Inspection and maintenance of fire doors, keys for the fire brigade, and marking of exit routes
9.5.1-1(g)	Sampling of water drainage for contamination following a fire
9.5.1-1(h)	Control of combustibles

9.5.1-1(i)	Portable radio communications for the fire brigade
9.5.1-1(j)	Fire protection inside containment during refueling and maintenance
9.5.1-1(k)	Control of combustibles in areas containing safety-related equipment
9.5.1-1(l)	Cooling tower fire protection
9.5.1-1(m)	Storage of welding gas cylinders
9.5.1-1(n)	Storage of ion exchange resins
9.5.1-1(o)	Storage of hazardous chemicals
9.5.1-2	Fire hazard analysis
9.5.1-3	Establishment of fire watches for fire areas breached during maintenance
9.5.1-4	Operator actions minimizing spurious ADS actuation
9.5.1-5	Deviations from NFPA codes and standards
9.5.1-6	Verification of field installed fire barriers
9.5.1-7	Fire resistance test data

9.5.2 Communication Systems

The staff reviewed the AP1000 communication systems in accordance with the SRP Section 9.5.2 acceptance criteria and the guidance in EPRI ALWR utility requirements document (URD). The criteria relies, in part, on the operating history of current plant communication systems. Communication systems are deemed acceptable if the integrated system can provide effective plant personnel communications for a variety of scenarios during normal, incident, and accident conditions and environments. Such environmental considerations include weather, moisture, noise level, and electromagnetic interference/radio-frequency interference (EMI/RFI) conditions which might interfere with the ability for effective communication to be accomplished in all vital areas. Environmental conditions also include fires and radiological events in which personnel must be able to effectively communicate through respiratory protection.

In Title 10 of the Code of Federal Regulations, Section 73.55(e), "Detection Aids," Section 73.55(f), "Communication Requirements," and Section 73.55(g), "Testing and Maintenance," contain design requirements for certain communication systems. These requirements are summarized as follows:

- secondary power supplies for nonportable communications equipment located in vital areas

- on-duty security personnel capable of continuous communication with individuals in manned alarm stations
- use of conventional telephone service
- use of continuous two-way communication in addition to conventional phone via radio or microwave
- nonportable equipment operable in the event of normal power loss
- communications equipment maintained in operable condition
- certain equipment tested on a shift basis or daily, as required by 10 CFR 73.55(g)

Chapter 10, Section 4.6.1, of the URD covers plant operations and maintenance communications, as well as external communications with outside organizations. The communication system designer should include the system requirements and an analysis to ensure the requirements meet the needs of the system. The URD also discusses that the primary and dedicated communication between operations and maintenance personnel should be portable and wireless with the appropriate support equipment. A plant-wide paging system and in-plant telephone system should be included. Dedicated phone links should be included to effect offsite communications.

DCD Tier 2, Section 9.5.2, "Communication System," contains the description of the communication system. The system consists of the following subsystems:

- wireless telephone system
- telephone/page system
- private automatic branch exchange system
- sound-powered system
- emergency response facility communications
- security communication system

According to the DCD, the private automatic branch exchange (PABX) system and wireless communications fulfill the requirements of 10 CFR 73.55(e) and (f). Communication devices to be used with respiratory equipment shall be designed and selected according to the guidelines of EPRI Report NP 6559, "Voice Communication Systems Compatible with Respiratory Protection."

The following paragraphs summarize the communication systems described in the DCD.

<u>Wireless Telephone System</u>

The AP1000 wireless telephone system consists of portable handsets and headsets, an antenna system, and wireless phone switch. This is the primary means of plant operations and maintenance personnel communications. The page, PABX phone, and sound-powered systems are backups to the wireless phone system. The system power backup is a UPS that will supply power for up to 2 hours, if normal power is lost.

Auxiliary Systems

Telephone/Page System

The telephone/page system consists of handsets, amplifiers, loudspeakers, tone generators, a test and distribution cabinet, and other support equipment. The system has one paging and five party lines. This allows zone paging, zone to zone paging, and all zone paging. This system is also used for certain alarms designated by the COL applicant. These alarm selections are controlled and programmed from the MCR. Alarm notification will automatically merge the zones for an alarm actuation. The system power backup is a UPS that will supply power for up to 2 hours, if normal power is lost.

Private Automatic Branch Exchange (PABX) System

The AP1000 PABX system provides communications between system stations. This system includes call transfer capability and conference calling. The MCR and TSC have additional capabilities to program selected numbers for particular stations. The PABX interfaces with the wireless phone system, local telephone systems, page system, and direct extensions outside the plant. The system power backup is a UPS that will supply power for up to 2 hours, if normal power is lost.

Sound-Powered System

The AP1000 sound-powered system is used for refueling and for startup and maintenance testing. It does not require an external power supply for operation.

The DCD states that the above-mentioned systems will be tested according to their use. That is, those systems not frequently used will be tested "at periodic intervals to demonstrate operability when required." For those systems that are routinely used, their very use will demonstrate that the system is operating correctly.

As discussed in DCD Tier 2, Section 9.5.2.5, the COL applicant is responsible for the emergency response facility communications and the security communication system. These two systems are discussed below.

Emergency Response Facility Communications

DCD Tier 2, Section 9.5.2.5.2, "Emergency Response Facility Communications," states that the COL applicant will address emergency response facility communications, including the crisis management radio system. This is COL Action Item 9.5.2-1.

Security Communication System

DCD Tier 2, Section 9.5.2.5.3, "Security Communications," states that the COL applicant will provide specific details about the security communication system, as described in DCD Tier 2, Sections 13.6.9 and 13.6.10. These sections state that upon a loss of normal power, the security communication system receives power from the security-dedicated UPS. The UPS is capable of sustaining operation for a minimum of 24 hours. The COL applicant will address specific details of the security communication system, including testing. This is COL Action Item 9.5.2-2.

The staff identified four open items in the DSER which were evaluated as follows:

(1) 10 CFR 73.55(e) and (f) discuss the placement of backup power supplies for certain communication systems in vital areas. This is mentioned in DCD Tier 2, Section 13.6, "Security," for "vital equipment," but it is not clear that the applicant considers the "non-portable communication equipment" specified in 10 CFR 73.55(f) to be vital equipment. Open Item 9.5.2-1 in the DSER identified that the DCD should clarify the categorization of communication equipment in accordance with 10 CFR 73.55(f). Westinghouse addressed this open item in a May 14, 2003, RAI response and updated DCD Tier 2, Section 13.6.9 to indicate that the COL applicant will be responsible for the design and design requirements of the backup power supply. This is a part of COL Action Item 9.5.2-2. This response is acceptable to the staff and, therefore, Open Item 9.5.2-1 is resolved.

(2) 10 CFR 73.55(g) discusses testing requirements for certain communication systems. Open Item 9.5.2-2 in the DSER identifies that this issue has not been addressed in DCD Tier 2, Section 9.5.2. Westinghouse addressed this open item in a May 14, 2003, RAI response in which it pointed out that DCD Tier 2, Section 13.5.1 states, in part, that "Combined License applicants referencing the AP1000 certified design will address plant procedures including... maintenance, inspection, test and surveillance." This is a part of COL Action Item 9.5.2-2. The applicant's response addressed the staff's concern regarding the testing of the security communication system and, therefore, Open Item 9.5.2-2 is resolved.

(3) The COL applicant should address the issue of NRC Bulletin 80-15 for recommendations concerning loss of the emergency notification system due to a LOOP. This is COL Action Item 9.5.2-3. Open Item 9.5.2-3 in the DSER recommends including this COL information in the DCD. In its July 7, 2003, RAI response, Westinghouse stated, "DCD Tier 2, [Section] 9.5.2.5.1 will be revised... to remind the COL applicant to review BL 80-15." The staff verified that the DCD was appropriately revised to reflect COL Action Item 9.5.2-3. This revision to the DCD is acceptable to the staff and, therefore, Open Item 9.5.2-3 is resolved.

(4) SRP Section 9.5.2 provides reviewer guidance on the design of communication systems (i.e., intraplant and plant to off site). Part of that guidance states, "Communication systems will be protected from EMI/RFI effects of other plant equipment and there will be adequate testing and field measurements where necessary to demonstrate effective communications." In addition, SRP Section 9.5.2 discusses the general requirement for communication equipment to provide effective communication during the "full spectrum of... conditions... under maximum potential noise levels."

The staff believes that the DCD does not adequately cover communication testing for plant startup and operations in sufficient detail, including the EMI/RFI effects on equipment, to understand how effective communications will be demonstrated. The staff also believes that the DCD does not sufficiently address how effective communications will be sustained during maximum potential noise levels. This is Open Item 9.5.2-4 in the DSER.

In its May 14, 2003, response, Westinghouse stated that DCD Tier 2, Section 14.2.9.4.13 discusses EMI/RFI testing. Westinghouse also stated that:

> test procedures will simulate the predicted worst-case EMI/RFI environment either by operating EMI/RFI producing equipment in the areas of the communication equipment being tested or by simulating the EMI/RFI environment which would result from the predicted worst-case operating configuration of this equipment.

Westinghouse also revised DCD Tier 2, Section 14.2.9.4.13 to address the issue of whether the communication equipment will be able to operate in maximum plant noise levels. The staff finds these responses, and the corresponding revision to the DCD to be acceptable and, therefore, Open Item 9.5.2-4 is resolved.

On the basis of the resolution of the above open items and its review of the design detail provided in the DCD, the staff concludes that the AP1000 communication systems will adequately provide effective communication.

9.5.3 Plant Lighting System

Regulatory Evaluation

The acceptance criteria in SRP Section 9.5.3 state that the acceptability of the design of the normal, emergency, panel, and security lighting is based on the degree to which the system design is similar to the design used in previously approved plants with satisfactory operating experience. No GDC or regulatory guides directly apply to the safety-related performance requirements for the lighting system. The lighting system for the AP1000 should be designed in accordance with SRP Section 9.5.3 and with lighting levels recommended in NUREG-0700, "Guidelines for Control Room Design Review," which is based on the Illuminating Engineering Society (IES) Lighting Handbook.

Technical Evaluation

The plant lighting system includes normal, emergency, panel, and security lighting. The normal and emergency lighting in the MCR and remote shutdown area are non-Class 1E. The normal lighting provides illumination during plant operating, maintenance, and test conditions. The emergency lighting provides illumination in areas where emergency operations are performed upon loss of normal lighting. The security lighting system is site specific and will be addressed by the COL applicant. This is discussed in Section 13.6.8 of this report.

9.5.3.1 Normal Lighting System

Power to the normal lighting system is supplied from the non-Class 1E power distribution system, and is backed up by the onsite standby DGs. The lighting load is distributed between the two DG buses. The motor control centers, powering the normal lighting system, are energized by the 480-V ac load centers. A lighting control system controls the lighting distribution panel branch circuit breakers. Approximately 75 percent of the normal lighting is tripped off automatically upon loss of normal ac power (except in the MCR and in the remote shutdown area). This limits the load on the onsite DGs. The lighting control system allows an operator to energize or deenergize lighting in selected areas, based on the actual need and available power from the onsite standby DG. The circuits to the individual ac lighting fixtures are staggered, to the extent practical. The staggered circuits are fed from separate buses to ensure that some lighting is retained in the event of a bus or circuit failure. The lighting fixtures located in the vicinity of safety-related equipment are supported so that they do not adversely impact this equipment when subjected to the seismic loading of an SSE.

Power to the normal lighting system is supplied from the non-Class 1E ac power distribution system at the following voltage levels:

- 480/277-V, 3-phase, 4-wire, grounded neutral system lighting panels are fed from the 480-V motor control centers. This source is for the lighting fixtures rated at 480/277 V and for the welding receptacles.
- 208/120-V, 3-phase, 4-wire, grounded neutral system distribution panels are fed from the 480-V motor control centers, through dry-type 480-208/120-V transformers. This source is for the convenience lighting and utility receptacles.
- 208/120-V, 3-phase, 4-wire, grounded neutral regulated power fed from 480-V motor control centers, through the Class 1E 480-208/120-V voltage regulating transformers (Division B and C). This source is for the normal and emergency lighting in the MCR and remote shutdown area, and is isolated through two series of fuses.

The staff considers the information provided to be sufficient to meet SRP Section 9.5.3 and, therefore, is acceptable.

9.5.3.2 Emergency Lighting

Power to the emergency lighting in the MCR and the remote shutdown area is supplied from the Class 1E 125-V dc switchboard through the Class 1E 208Y/120 V ac inverters, and is isolated through two series of fuses. Three-hour barrier separation is provided between redundant emergency power supplies and cables outside the MCR and the remote shutdown area. The control room lighting complies with human factors engineering requirements by using semi-indirect, low-glare lighting fixtures and programmable dimming features. The control room emergency lighting is integrated with the normal lighting, which consists of identical lighting fixtures and dimming features. The emergency lighting system is designed so that, to the extent possible, alternate emergency lighting fixtures are fed from separate divisions of the Class 1E dc and UPS system. Both normal and emergency lighting fixtures, controllers, dimmers, and the associated cables used in the MCR and remote shutdown area are non-Class 1E. The ceiling grid network, raceways, and fixtures utilize seismic supports.

Following the 72-hour period after a loss of all ac power sources, the lighting circuits in the MCR will be powered from two ancillary ac generators.

In areas outside the MCR and the remote shutdown area, emergency lighting is provided by 8-hour, self-contained, battery-pack, sealed-beam lighting units. These units are powered from the non-Class 1E and provide illumination for safe ingress and egress of personnel following a loss of normal lighting in areas that are involved in power recovery. In addition, these units are provided in areas where normal actions are required for operation of equipment needed during a fire. These units are normally powered from the non-Class 1E 480/277-V ac motor control centers.

The staff considers the information provided to be sufficient to meet SRP Section 9.5.3 and, therefore, is acceptable.

9.5.3.3 Panel Lighting

Panel lighting is designed to provide lighting in the MCR at the safety panels. It consists of lighting fixtures located on or nearby the safety panels in the MCR. The panel lights are continuously energized. The fixtures are powered from the Division B and C Class 1E inverters through Class 1E distribution panels. The circuits are treated as Class 1E. The panel lighting circuits up to the lighting fixtures are classified as associated and routed in seismic Category I raceways. The bulbs are not seismically qualified.

The staff has evaluated and determined that the panel lighting design is acceptable because the panel lighting circuits to the lighting fixtures are powered from the Division B and C Class 1E inverters, through Class 1E distribution panels, and are routed in seismic Category I raceways.

9.5.3.4 Conclusions

Based on its review, the staff concludes that the lighting system for the AP1000 is in accordance with SRP Section 9.5.3 and with the lighting levels recommended in NUREG-0700, which is based on the IES Lighting Handbook. Therefore, the design is acceptable.

9.5.4 Standby Diesel Generator Auxiliary Support Systems

There are two redundant onsite standby DG units in the AP1000 design. These will provide power, assuming a single active component failure, to selected non-safety-related ac loads in the event of a loss of normal and preferred ac power supplies. Each standby DG unit is an independent system complete with its necessary support systems that include the following:

- standby DG cooling system
- standby DG starting system
- standby DG lubricating oil system
- standby DG combustion air intake and exhaust system

The standby DGs and their support systems have no safety-related functions and, therefore, have no nuclear safety design basis. They are classified as AP1000 Class D, nonseismic systems, which incorporate standard industrial quality assurance standards to provide appropriate integrity and function. The standby DGs and their support systems are also included in the AP1000 IPSAC and D-RAP programs.

In addition to the two standby DG units, two redundant ancillary ac DGs are located in the annex building to provide long-term backup ac power supplies for postaccident monitoring, MCR lighting, MCR and I&C room ventilation, and PCS and SFP water makeup when all other sources of power are unavailable. The ancillary DGs are not needed for the first 72 hours following a loss of all other ac sources. The ancillary DGs, classified as AP1000 Class D systems, are commercial-grade, skid-mounted, self-contained units packaged with all necessary support systems and controls. The ancillary DGs are also included in the AP1000 IPSAC and D-RAP programs. Section 8.3 of this report presents the staff's evaluation of the ancillary DGs.

9.5.5 Standby Diesel Generator Cooling System

The staff followed the guidance of SRP Section 9.5.5, "Emergency Diesel Engine Cooling Water System," to review the standby DG cooling system in the AP1000 design. The acceptance criteria in SRP Section 9.5.5 are based on meeting the applicable requirements of GDC 2, 4, 5, 17, 44, 45, and 46.

The AP1000 standby DG cooling system serves no safety-related function and, therefore, has no nuclear safety design basis. The system is an independent, closed-loop cooling system, rejecting engine heat through two separate roof-mounted, fan-cooled radiators. The system consists of two separate cooling loops, each maintained at a temperature required for optimum engine performance by separate engine-driven, coolant water circulating pumps. One loop cools the engine cylinder block, jacket, and head area, while the other loop cools the oil cooler and turbocharger aftercooler. The cooling loop, which cools the engine cylinder blocks, jacket, and head areas, includes a keep-warm circuit consisting of a temperature-controlled electric heater and an ac motor-driven water circulating pump.

Based on its review, the staff determined that the standby DG cooling system is a non-safety-related system and serves no safety-related function. Its failure does not lead to the failure of any safety systems. The staff, therefore, concludes that the requirements of GDC 2, 4, 5, 17, 44, 45 and 46, and the guidance of SRP Section 9.5.5, do not apply. In addition, as described in Section 9.5.4 of this report, the standby DG unit, which includes the standby DG cooling system, is classified as an AP1000 Class D system, and is included in the AP1000 IPSAC and D-RAP programs. On the basis of the above information, as well as the fact that its failure does not prevent safe shutdown, the staff finds the standby DG cooling system to be acceptable.

9.5.6 Standby Diesel Generator Starting System

The staff followed the guidance of SRP Section 9.5.6, "Emergency Diesel Engine Starting System," to review the standby DG starting system in the AP1000 design. The acceptance criteria in SRP Section 9.5.6 are based on meeting the applicable requirements of GDC 2, 4, 5, and 17.

The AP1000 standby DG starting system serves no safety-related function and, therefore, has no nuclear safety design basis. The system consists of an ac motor-driven, air-cooled compressor, a compressor inlet air filter, an air-cooled aftercooler, an in-line air filter, a refrigerant dryer, and an air receiver with sufficient storage capacity for three diesel engine starts. In DCD Tier 2, Section 8.3.1.1.2.1, Westinghouse stated that the DG starting system will be consistent with the manufacturer's recommendations regarding the devices to crank the engine, duration of the cranking cycle, the number of engine revolutions per start attempt, volume and design pressure of the air receivers, and compressor size.

Based on its review, the staff determined that the standby DG starting system is a non-safety-related system and serves no safety-related function. Its failure does not lead to the failure of any safety systems. The staff, therefore, concludes that the requirements of GDC 2, 4, 5, and 17, and the guidance of SRP Section 9.5.6, do not apply. In addition, as described in Section 9.5.4 of this report, the standby DG unit, which includes the standby DG starting system, is classified as an AP1000 Class D system, and is included in the AP1000 IPSAC and D-RAP programs. On the basis of the above information, as well as the fact that its failure will not prevent safe shutdown, the staff finds the standby DG starting system to be acceptable.

9.5.7 Standby Diesel Generator Lubricating Oil System

The staff followed the guidance of SRP Section 9.5.7, "Emergency Diesel Engine Lubrication System," to review the standby DG lubricating oil system in the AP1000 design. The acceptance criteria in SRP Section 9.5.7 are based on meeting the applicable requirements of GDC 2, 4, 5, and 17.

The AP1000 standby DG lubricating oil system serves no safety-related function and, therefore, has no nuclear safety design basis. The system is contained on the engine skid and includes an engine oil sump, a main engine-driven oil pump, and a continuous engine prelube system consisting of an ac and dc motor-driven prelube pump and electric heater. The prelube system maintains the engine lubrication system in service when the DG is in standby mode. The lube oil is circulated through the engine and various filters and coolers to maintain the lube oil properties suitable for engine lubrication.

Based on its review, the staff determined that the standby DG lubricating oil system is a non-safety-related system and serves no safety-related function. Its failure does not lead to the failure of any safety systems. The staff, therefore, concludes that the requirements of GDC 2, 4, 5 and 17, and the guidance of SRP Section 9.5.7, do not apply. In addition, as described in Section 9.5.4 of this report, the standby DG unit, which includes the standby DG lubricating oil system, is classified as an AP1000 Class D system, and is included in the AP1000 IPSAC and D-RAP programs. On the basis of the above information, as well as the fact that its failure will not prevent safe shutdown, the staff finds the standby DG lubricating oil system to be acceptable.

9.5.8 Standby Diesel Generator Combustion Air Intake and Exhaust System

The staff followed the guidance of SRP Section 9.5.8, "Emergency Diesel Engine Combustion Air Intake and Exhaust System," to review the standby DG combustion air intake and exhaust system in the AP1000 design. The acceptance criteria in SRP Section 9.5.8 are based on meeting the applicable requirements of GDC 2, 4, 5, and 17.

The AP1000 standby DG combustion air intake and exhaust system serves no safety-related function and, therefore, has no nuclear safety design basis. The system provides combustion air directly from the outside to the diesel engine while protecting it from dust, rain, snow, and other environmental particulates. It then discharges exhaust gases from the engine to the outside of the DG building more than 20 feet above the air intake. The combustion air circuit includes weather-protected, dry-type inlet air filters piped directly to the inlet connections of the diesel engine-mounted turbochargers. The engine exhaust gas circuit consists of the engine exhaust gas discharge pipes from the turbocharger outlets to a single vertically mounted outdoor silencer which discharges to the atmosphere. The applicant stated that it considered the manufacturer's recommendations in the design of features to protect the silencer module and other system components from possible clogging due to adverse atmospheric conditions, such as dust storms, rain, ice, and snow.

Based on its review, the staff determined that the standby DG combustion air intake and exhaust system is a non-safety-related system and serves no safety-related function. Its failure does not lead to the failure of any safety systems. The staff, therefore, concludes that the requirements of GDC 2, 4, 5 and 17, and the guidance of SRP Section 9.5.8, do not apply. In addition, as described in Section 9.5.4 of this report, the standby DG unit, which includes the standby DG combustion air intake and exhaust system, is classified as an AP1000 Class D system, and is included in the AP1000 IPSAC and D-RAP programs. On the basis of the above information, as well as the fact that its failure will not prevent safe shutdown, the staff finds the standby DG combustion air intake and exhaust system to be acceptable.

9.5.9 Diesel Generator and Auxiliary Boiler Fuel Oil System

The staff followed the guidance of SRP Section 9.5.4, "Standby Diesel Generator Fuel Oil Storage and Transfer System," to review this system. The acceptance criteria in SRP Section 9.5.4 are based on meeting the applicable requirements of GDC 2, 4, 5, and 17.

The AP1000 DG and auxiliary boiler fuel oil system serves no safety-related function and, therefore, has no nuclear safety design basis. The function of the DG and auxiliary boiler fuel oil system is to store and provide fuel oil for the onsite non-safety-related standby DGs, the auxiliary boiler, and the ancillary DGs. The system is designed to provide a supply of fuel oil sufficient to operate each standby DG at a continuous rating for 7 days, provide a 7-day fuel supply for auxiliary boiler operation, with half of the required fuel stored in each tank, and provide a 4-day fuel supply for the two ancillary DGs. The system is classified as an AP1000 Class D system and is included in the AP1000 IPSAC and D-RAP programs.

The DG and auxiliary boiler fuel oil system consists of two independent, full-capacity standby DG fuel oil storage and transfer systems, one for each standby DG (i.e., the auxiliary boiler fuel oil supply system and the ancillary DG fuel oil supply system).

The fuel oil storage tanks for the standby DGs and auxiliary boiler are replenished from trucks (or other mobile suppliers) as required to maintain an adequate fuel supply for the auxiliary boilers and a 7-day fuel supply for each standby DG. Each storage tank is equipped with a vent line to the atmosphere at the top of the tank. This vent line ends with a flame arrester. A tank fill line runs to each tank and is extended to the truck unloading station. The fill line incorporates a normally closed valve and a filler cap at the end to preclude the entrance of water. The fill line is above grade. The fill line has a strainer located downstream of the isolation valve to prevent entrance of deleterious solid material into the tank. A water removal port is located at the tank sump.

Each fuel oil transfer pump takes suction from a fuel oil storage tank and discharges fuel oil to the DG fuel oil day tank. Each pump is capable of supplying its DG and, simultaneously, increasing the inventory in the fuel oil day tank. The fuel oil transfer pump is automatically started and stopped based on day tank level control. Part of the pump discharge flow is returned to the storage tank via the recirculation line. The filter in the discharge line to the day tank is monitored by measuring differential pressures across the filter and by providing a high differential pressure alarm. The fuel oil storage tank for each standby DG also provides fuel oil for the auxiliary boiler. Fuel oil for the standby DG is reserved by tapping auxiliary boiler fuel oil from elevated nozzles above the required DG fuel oil storage level.

In DCD Tier 2, Section 9.5.4.7 Westinghouse states that Combined License applicants referencing the AP1000 certified design will address the site-specific need for cathodic protection in accordance with NACE Standard RP-01-69 for external metal surfaces of metal tanks in contact with the ground. This is COL Action Item 9.5.9-1. Westinghouse also states in DCD Tier 2, Section 9.5.4.7 that Combined License applicants referencing the AP1000 certified design will address site-specific factors in the fuel oil storage tank installation specification to reduce the effects of sun heat input into the stored fuel, the diesel fuel specifications grade and the fuel properties consistent with manufacturers' recommendations, and will address measures to protect against fuel degradation by a program of fuel sampling and testing. This is COL Action Item 9.5.9-2.

Fuel oil to the auxiliary boiler is supplied by two suction supply lines (one from each tank) to two separate fuel oil supply pumping stations. One auxiliary boiler fuel oil pumping station is located in each DG fuel transfer pump enclosure. Both pumps discharge to the auxiliary boiler through a common discharge line. The pumps are full capacity, with one for service and the other as standby. The pump motor and pump are mounted on a common base plate. The system includes a recirculation fuel oil return line from the boiler back to the storage tanks.

The fuel oil storage tank for the ancillary DGs, which consists of a single 100-percent capacity tank serving both ancillary DGs, is replenished from trucks (or other mobile suppliers) as required to maintain a 4-day fuel supply for both DGs. The ancillary DG fuel oil storage tank is seismic Category I and is located in the same room as the generators.

Based on its review, the staff determined that the DG and auxiliary boiler fuel oil system is a non-safety-related system and serves no safety-related function. Its failure does not lead to the failure of any safety systems. The staff, therefore, concludes that the requirements of GDC 2, 4, 5 and 17, and the guidance of SRP Section 9.5.4, do not apply. In addition, as described above, the DG and auxiliary boiler fuel oil system is classified as an AP1000 Class D system, and is included in the AP1000 IPSAC and D-RAP programs. On the basis of the above information, as well as the fact that its failure will not prevent safe shutdown, the staff finds the DG and auxiliary boiler fuel oil system to be acceptable.

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10. SUPPLEMENTARY NOTES

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11. ABSTRACT *(200 words or less)*

This final safety evaluation report documents the technical review of the AP1000 standard nuclear reactor design by the U.S. Nuclear Regulatory Commission (NRC). Westinghouse Electric Company submitted the application for the AP1000 design on March 28, 2002, in accordance with Title 10 of the Code of Federal Regulations (10 CFR) Part 52, SubpartB, "Standard Design Certifications," and 10 CFR Part 52, Appendix O, "Standardization of Design: Staff Review of Standard Designs." The AP1000 nuclear reactor design is a pressurized water reactor with a power rating of 3415 megawatts thermal (MWt) and an electrical output of at least 1000 megawatts electric (MWe). The AP1000 design contains many features that are not found in current operating reactors. For example, a variety of engineering and operational improvements provide additional safety margins and address the Commission's severe accident, safety goal, and standardization policy statements. The most significant improvement to the design is the use of safety systems that employ passive means, such as gravity, natural circulation, condensation and evaporation, and stored energy, for accident mitigation. These passive safety systems perform safety injection, residual heat removal, and containment cooling functions. Some features of the AP1000, compared to currently operating reactors, include a longer reactor core design, a larger pressurizer, an in-containment refueling water storage tank, an automatic depressurization system, a revised main control room design with a digital microprocessor-based instrumentation and control system, hermetically sealed canned reactor coolant pump motors mounted to the steam generator, and increased battery capacity. In addition, the facility is designed for a 60-year life, which exceeds the projected 40-year combined operating license period, and employs structural modules. On the basis of its evaluation and independent analyses, as set forth in this report, the NRC staff concludes that Westinghouse's application for design certification meets the requirements of 10CFR Part 52, Subpart B, that are applicable and technically relevant to the AP1000 standard design.

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