10 STEAM AND POWER CONVERSION SYSTEM

10.1 Introduction

The steam and power conversion system is designed to convert the heat energy generated by the reactor into electric power. The steam and power conversion system for the AP1000 design is described in the AP1000 Design Control Document (DCD) Tier 2 Chapter 10, "Steam and Power Conversion." This system generates electricity by using the main steam system to drive a turbine generator unit. Two steam generators produce steam from the heat energy generated by the reactor to supply the turbine for the main steam system.

The turbine exhaust steam is condensed and deaerated in the main condenser. The heat rejected in the main condenser is removed by a closed-loop circulating water system (CWS). The condensate pumps take suction from the condenser and deliver the condensate water through heaters to the suction of the main feedwater booster pump. The water is then discharged to the suction of the main feedwater pumps, which discharge the feedwater through feedwater heaters to the two steam generators.

Steam from each of two steam generators enters the high-pressure turbine through four stop valves and four governing control valves. Crossties are provided upstream of the turbine stop valves to equalize pressure. The turbine bypass system provides the capability to relieve a combined capacity of 40 percent of total full-power steam flow to the condenser during startup, hot shutdown, cooldown, and step-load reductions in generator loads.

The protective features for the steam and power conversion system include the following:

- loss of external electrical load and/or turbine trip protection,
- main steamline overpressure protection,
- loss of main feedwater flow protection,
- turbine overpressure protection,
- turbine missile protection,
- radioactivity protection, and
- erosion-corrosion protection.

Spring-loaded safety valves are provided on both main steamlines for the overpressure protection, in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III. The pressure relief capacity of the safety valves is such that the energy generated at the high-flux reactor trip setting can be dissipated through this system. The design capacity of the main steam safety valves equals or exceeds 105 percent of the nuclear steam supply system (NSSS) design steamflow at an accumulation pressure not exceeding 110 percent of the main steam system design pressure.

The steam and power conversion system description, design features, and performance characteristics are identified in DCD Tier 2 Section 10.1, and Table 10.1-1.

10.2 Turbine Generator

The staff reviewed the design of the turbine generator in accordance with Section 10.2 of the standard review plan (SRP). The design of the turbine generator system is acceptable if the integrated design of the system meets the requirement of Title 10 of the Code of Federal Regulations (10 CFR) Part 50, Appendix A, General Design Criteria for Nuclear Power Plants (GDC) 4, “Environmental and dynamic effects design bases,” as related to the protection of the structures, systems, and components (SSCs) that are important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generation of turbine missiles. Specific criteria necessary to meet the requirements of GDC 4 are described in SRP Section 10.2.II.

The turbine generator converts the thermal energy into electric power. The Westinghouse turbine generator is designated as Model TC6F with a 137 cm (54 in.) last-stage blade unit. The AP1000 turbine generator has a heat balance output value of 1,199,500 kW for the Westinghouse NSSS rated thermal power of 3,415 MWt.

The design parameters of the turbine generator are identified in DCD Tier 2 Table 10.2.1. The piping and instrumentation diagram containing the stop, governing control, intercept, and reheat valves is shown in DCD Tier 2 Figure 10.3.2-2. The turbine generator consists of a double-flow, high-pressure turbine and three double-flow, low-pressure turbines. Other related system components include: a turbine-generator bearing lubrication oil system, a digital electrohydraulic (DEH) control system, a turbine steam sealing system, overspeed protective devices, turning gear, a generator hydrogen and seal oil system, a generator carbon dioxide system, an exciter cooler, a rectifier section, and a voltage regulator.

The design of the turbine generator foundation is a spring-mounted support system. The springs dynamically isolate the turbine generator deck from the remainder of the structure in the range of operating frequencies.

Steam from each of two steam generators enters the high-pressure turbine through stop valves and governing control valves. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheaters. The reheated steam flows through separate reheat stop and intercept valves leading to the inlets of the three low-pressure turbines. Turbine steam is supplied to feedwater heaters.

10.2.1 Overspeed Protection

The overspeed protection control of the DEH control system and the emergency trip system (ETS) are provided to protect the turbine against overspeed.

The overspeed protection control of the DEH control system opens a drain path for the hydraulic fluid in the overspeed protection control header if turbine speed exceeds 103 percent of rated speed. The loss of fluid pressure in the header causes the control and intercept valves to close. Following the above valve closure, if the turbine speed falls below rated speed and the header pressure is reestablished, the control and intercept valves are reopened, and the unit resumes speed control. Additional discussion of the DEH control system is in Section 10.2.2 of this safety evaluation report. In addition, an emergency trip system is provided to trip the turbine, in the event that speeds exceed the overspeed protection control trip setpoints (110 percent of rated speed). Additional discussion of the ETS is in Section 10.2.4 of this report.

10.2.2 Digital Electrohydraulic Control System

The turbine generator is equipped with a DEH control system. The DEH control system has two modes of operation to protect the turbine from overspeeding. The first is the speed control that functions to maintain the desired speed, and the second mode is the overspeed protection control, which operates if the normal speed control should fail or upon a load rejection.

The DEH control system combines the capabilities of redundant processors and high-pressure hydraulics to regulate steam flow through the turbine. The control system provides the functions of speed control, load control, and automatic turbine control (ATC). The ATC is discussed in Section 10.2.3 of this report. Valve opening actuation in the DEH control system is provided by a hydraulic system while closing actuation is provided by springs and steam forces upon reduction or relief of fluid pressure. A trip signal is sent to a fast acting solenoid valve. Energizing the solenoid valves releases the hydraulic fluid pressure in the valve actuators, allowing springs to close each valve. The system is designed so that loss-of-fluid pressure leads to valve closure and consequent turbine trip. Steam valves are provided in series pairs. A stop valve is tripped by the overspeed trip system; the control valve is modulated by the governing system and actuated by the trip system.

10.2.3 Automatic Turbine Control

Automatic turbine control regulates turbine speed and acceleration through the entire speed range. When the operator selects ATC, the programs both monitor and control the turbine.

The ATC is capable of automatically performing the following activities:

- changing speed,
- changing acceleration,
- generating speed holds,
- changing load rates, and
- generating load holds.

10.2.4 Turbine Protective Trips

The turbine protective trips are independent of the electronic control system, and when initiated, cause tripping of the turbine stop and control valves. The protective trips are as follows:

- low bearing oil pressure,
- low electrohydraulic fluid pressure,
- high condenser back pressure,
- turbine overspeed,
- thrust bearing wear, and
- remote trip that accepts external trips.

The ETS discussed in Section 10.2.1 of this report is designed for the turbine overspeed trip. The ETS can detect undesirable operating conditions of the turbine generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the corrective actions. The ETS consists of the following: an emergency trip control block, trip solenoid valves, mechanical overspeed device, three test trip blocks with pressure sensors and test solenoid valves, rotor position pickups, speed sensors, and a test panel.

The ETS utilizes a two-channel configuration which permits online testing with continuous protection afforded during the test sequence. A trip of the ETS opens a drain path for the hydraulic fluid in the auto stop emergency trip header. The loss of fluid pressure in the trip header causes the main stop and reheat stop valves to close. Also, check valves in the connection to the overspeed protection control header open to drop the pressure and cause the control and intercept valves to close. The control and intercept valves are redundant to the main stop and reheat stop valves respectively. DCD Tier 2 Section 10.2.2.8 states that major system components are readily accessible for inspection and are available for testing during normal plant operation, and that turbine trip circuitry is tested prior to unit startup.

The staff reviewed the above information, as described in DCD Tier 2 Sections 10.2.1 through 10.2.3, to confirm that there is sufficient redundancy on turbine overspeed protection. The staff determined that the AP1000 turbine generator design is in conformance with Acceptance Criteria II.1 and II.4 of Section 10.2 of the SRP.

The mechanical overspeed trip device consists of a spring-loaded trip weight mounted in the rotor extension shaft. The mechanical overspeed and manual trip header can be tripped manually via a trip handle mounted on the governor pedestal. The electrical overspeed trip system has separate, redundant speed sensors and provides backup overspeed protection utilizing the trip solenoid valves in the emergency trip control block to drain the emergency trip header. The speed control and overspeed protection function of the DEH control system combined with the ETS electrical and mechanical overspeed trips provide sufficient level of redundancy and diversity.

10.2.5 Valve Control

Criterion II.2 of Section 10.2 of the SRP states that turbine main steam stop and control valves and reheat steam stop and intercept valves should be provided to protect the turbine from exceeding set speeds and to protect the reactor system from abnormal surges. The reheat stop and intercept valves should be capable of closure concurrent with the main steam stop valves, or of sequential closure within an appropriate time limit, to assure that turbine overspeed is controlled within acceptable limits. The valve arrangements and valve closure times should be such that a failure of any single valve to close will not result in an excessive turbine overspeed in the event of a turbine generator system trip signal.

DCD Tier 2 Section 10.2.2.4.3 states that the flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. Each stop valve is controlled by an electrohydraulic actuator, so that the stop valve is either fully open or fully closed. The function of the stop valves is to shut off the steam flow to the turbine when required. The stop valves fully close within 0.3 seconds of actuation of the ETS devices, which are independent of the electronic flow control unit.

The turbine control valves are positioned by electrohydraulic servo actuators in response to signals from their respective flow control units. The flow control unit signal positions the control valves for wide-range speed control through the normal turbine operating range, and for load control after the turbine generator unit is synchronized.

The reheat stop and intercept valves, located in the hot reheat lines at the inlet to the low-pressure turbines, control steam flow to the low-pressure turbines. During normal operation of the turbine, the reheat stop and intercept valves are wide open. The intercept valve flow control unit positions the valve during startup and normal operations, and closes the valve rapidly on loss of turbine loads. The reheat stop valves close completely on a turbine overspeed and turbine trips. Quick closure of the steam valves prevents a turbine overspeed. The valve closure time for both the reheat stop valves and intercept valves is 0.3 seconds. Because redundancy is built into the overspeed protection systems, the failure of a single valve will not disable the trip functions.

On the basis of the above discussion, the staff concludes that the AP1000 design is in conformance with Criteria II.2 and II.3 of Section 10.2 of the SRP with respect to the availability and adequacy of the control valves.

10.2.6 Turbine Missiles

The turbine generator and associated piping, valves, and controls are located completely within the turbine building. There are no safety-related systems or components located within the turbine building. The orientation of the turbine generator is such that a high-energy missile would be directed at a 90-degree angle away from safety-related structures, systems, or components. Failure of turbine generator equipment does not preclude a safe shutdown of the reactor. The issue of turbine missiles is addressed in Section 3.5.1.3 of this report.

10.2.7 Access to Turbine Areas

Criterion II.6 of Section 10.2 of the SRP states that unlimited access to all levels of the turbine area under all operating conditions should be provided. Radiation shielding should be provided as necessary to permit access.

Under operating conditions, there is access to turbine generator components and instrumentation associated with a turbine generator overspeed protection. Major system components are readily accessible for inspection, and are available for testing during normal plant operation.

Since the steam generated in the steam generators is not normally radioactive, no radiation shielding is provided for the turbine generator and associated components. Radiological considerations do not affect access to system components during normal conditions.

Based on the above discussion, the staff concludes that the turbine generator design is in conformance with Criterion II.6 of Section 10.2 of the SRP. Furthermore, Criterion II.7 of Section 10.2 of the SRP states that connection joints between the low-pressure turbine exhaust and the main condenser should be arranged to prevent adverse effects on any safety-related equipment in the turbine room in the event of rupture (it is preferable not to locate safety-related equipment in the turbine room). Criterion II.7 is satisfied because no safety-related equipment is located in the turbine building.

10.2.8 Turbine Rotor Integrity

GDC 4 requires that SSCs important to safety shall be appropriately protected against environmental and dynamic effects, including the effects of missiles, that may result from equipment failure. Because turbine rotors have large masses and rotate at relatively high speeds during normal reactor operation, failure of a rotor may result in the generation of high-energy missiles and cause excessive vibration of the turbine rotor assembly. The staff reviewed the measures taken by Westinghouse to ensure turbine rotor integrity and reduce the probability of turbine rotor failure.

The staff used the guidelines of SRP Section 10.2.3, “Turbine Disk Integrity,” to review and evaluate the information submitted by Westinghouse to ensure turbine rotor integrity and a low probability of turbine rotor failure with the generation of missiles. SRP Section 10.2.3 provides criteria to ensure that the turbine rotor materials have acceptable fracture toughness and elevated temperature properties, and the rotor is adequately designed and inspected prior to service and receives in-service inspections (ISIs) at approximately 10-year intervals during plant shutdowns.

Westinghouse provided its evaluation on turbine disk integrity which addressed all technical areas specified in SRP 10.2.3: materials selection, fracture toughness, preservice inspection, turbine disk design, and ISI. Westinghouse relies on the turbine missile methodology and analytical results documented in WCAP-15783, “Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines,” and WCAP-15785, “Probabilistic Evaluation of Turbine Valve Test Frequency,” for this evaluation. Description of the analyses and the staff’s evaluation and acceptance of WCAP-15783 and WCAP-15785 provided in Section 3.5.1.3 of this report is not repeated here.

DCD Tier 2 Section 10.2.3 provided information concerning the turbine rotor material. AP1000 turbine rotors are made from a vacuum-melted, deoxidized Ni-Cr-Mo-V alloy steel by processes which maximize steel cleanliness and provide adequate fracture toughness. DCD Tier 2 Section 10.2.3 indicates that the turbine rotors are made from forgings made to the requirements of materials specification ASTM A470, Class 5, 6, and 7, with strict limits being imposed on phosphorous, aluminum, antimony, tin, argon, and copper. This is a typical material used for Westinghouse turbine rotors and has been found to perform acceptable in service. The staff also finds this specification acceptable because use of this specification limits these impurities in the turbine rotor. The use of this materials specification is a necessary step in the process of assuring an appropriate level of fracture toughness.

Westinghouse stated in DCD Tier 2 Section 10.2.3.1, “Materials Selection,” that the turbine materials have the lowest fracture appearance transition temperature(FATT) and the highest C_V properties obtainable from water-quenched Ni-Cr-Mo-V material of the size and strength level used, indicating that suitable material toughness is obtained through the use of these types of material. Westinghouse’s response to request for additional information (RAI) 251.023 resolved the NRC staff’s concern about FATT and the ni-ductility temperature (NDT). The response to RAI 251.024 dated March 25, 2003, clarified Westinghouse’s fracture toughness requirements. This response indicates that the fracture toughness of the rotor materials will be at least 220 MPa$\sqrt{}$m (200 ksi$\sqrt{}$in), and the ratio of fracture toughness to the maximum applied stress intensity factor for rotors at speeds from normal to design overspeed will be at least two. The staff finds these toughness and margin criteria to be acceptable because they are consistent with criteria approved for other applications involving assumed flaws, such as the reactor pressure vessel pressure-temperature limits. However, this criterion is not consistent with what is stated in DCD Tier 2 Section 10.2.3.4. This is DSER Open Item 10.2.8-1.

In DCD Tier 2 Section 10.2.3.2, “Fracture Toughness,” Westinghouse discusses, in general terms, the maximum initial flaw size and crack growth rates. The staff evaluation of the application of non-destructive examination (NDE), initial flaw size, and crack growth rates, in terms of addressing the probability aspects of turbine missile generation, is discussed in Section 3.5.1.3 of this report. To ensure that the maximum applied stress intensity factor for rotors at various speed was derived appropriately, the NRC staff reviewed DCD Tier 2 Section 10.2.3.2.1, “Brittle Fracture Analysis,” and requested additional information in RAIs 251.025, 251.026, and 251.027, for resolving certain concerns about this analysis.

DCD Tier 2 Section 10.2.3.2.1 described a brittle fracture analysis considering the design duty cycle stresses, number of cycles, ultrasonic examination capability and growth rate of potential flaws. In its response to RAI 251.025 regarding the conservative factors of safety that were included in estimating the above-mentioned parameters, Westinghouse referred to the low cycle fatigue (LCF) crack analysis of WCAP-15783. (WCAP-15783 is used to support the NRC staff’s review of turbine missiles in DCD Tier 2 Section 3.5.1.3, as well as to support the turbine rotor integrity of DCD Tier 2 Section 10.2.3.) The brittle fracture analysis described in Section 10.2.3.2.1 is completely contained in WCAP-15783. The staff considers this response appropriate because it is clear that the operational stresses in the shaft are much lower than the operational stresses in the disks, making the disks more limiting than the shaft. Hence, the WCAP-15783 analyses for disks are sufficient for assessing overall rotor integrity. In the revised WCAP-15783, Westinghouse replaced an unreasonable K_{Ic} value used in the LCF analysis, as identified in RAI 251.025, by a reasonable proprietary value. In its response to RAI 251.026 dated March 25, 2003, regarding the vibratory stresses, Westinghouse referred to WCAP-15783 and stated that “(t)he vibratory stress when passing through critical speeds during startups and shutdowns is not included in the evaluation of low cycle fatigue. This is because the bending stress for this condition is greatest on the surface of the rotor and negligibly small on the rotor bore surface, which is the point where maximum stress of low cycle fatigue appears.” The NRC staff considers this to be appropriate because the vibratory stress occurred at a different location, not the place where LCF effect is evaluated. However, the response has not provided adequate justification to conclude that rotor resonant stresses resulting from passing through rotor critical speeds are insignificant. This is DSER Open Item 10.2.8-2.

In its response to RAI 251.027 regarding the K_{Ic} value and its associated safety factor and the assumed initial flaw depth that was used in the fatigue crack growth analysis, Westinghouse stated that the requested information can be found in WCAP-15783. Further, Westinghouse addressed the issue regarding the assumed initial crack depth in its response to RAI 251.002(a) on undetected and reported indications. The crack growth analysis and results due to LCF have been evaluated and accepted in the staff’s evaluation of DCD Tier 2 Section 3.5.1.3 related to turbine missiles; however, the determination of an initial flaw depth is addressed as RAI 251.002. This is DSER Open Item 3.5.1.3-1.

In RAI 251.028, the NRC staff discussed concerns about the uncertainties involved in using the results from the mechanical property tests, such as FATT, C_V, and yield strength, in the verification of the fracture toughness for rotor materials. In its response to RAI 251.028 dated March 25, 2003, regarding the assumed K_{Ic} value of 220 Mpa*√m (200 ksi√in) and the use of actual Combined License (COL) applicant plant-specific rotor test data to support this assumed value, Westinghouse states that for LCF evaluations, the assumed fracture toughness is based on the design curves for fracture toughness of 3.5 percent Ni-Cr-Mo-V steel. The fracture toughness curves provided reflect MHI test data and experience and include a 20 percent margin. Westinghouse further states "[t]he minimum allowable fracture toughness for the AP1000 [low pressure] LP rotor at temperature will be 220 Mpa*√m = 200 ksi*√in." This expected fracture toughness is supported by approximately 190 actual toughness values for MHI rotors calculated by using the Rolfe-Novak-Barsom correlation formula. The staff determined that there is ample margin between the assumed K_{Ic} value used in the LCF evaluations and the expected K_{Ic} value of 220 Mpa*√m (200 ksi*√in) for an actual rotor, especially when the assumed K_{Ic} value includes 20 percent margin. However, as required by DCD Tier 2 Section 10.2.6 and the COL applicant referencing the AP1000 design will have available plant-specific turbine rotor test data and calculated toughness curves to confirm the material property assumptions in the turbine rotor analysis. (Refer to Section 10.5 of this report, COL Action Item 10.52)

DCD Tier 2 Section 10.2.3.4, "Turbine Rotor Design," indicates that the AP1000 turbine rotor design will be a solid-forging, fully-integral rotor rather than disks shrunk on a shaft. The current practice employed by some turbine manufacturers for the large, LP, fully-integral rotors is to bore the center to remove metal impurities and permit internal inspection. The fully-integral, forged rotors will not be as susceptible to stress corrosion cracking (SCC) as the shrunk-on disks because of the reduction of surfaces susceptible to SCC and elimination of interference fits which induce higher stresses. The non-bored design of the high pressure (HP) rotors provides increased design margins because of inherently lower centerline stress. The use of solid rotor forgings was qualified by evaluation of the material removed from center bored rotors that were used in fossil power plants. This evaluation demonstrated that the material at the center of the rotors meets the requirements of the material specification. Further, supply of forgings for the HP rotors is limited to suppliers that have been qualified based on bore materials performance. Therefore, both the non-bored design of the HP turbine element and the bored design of the LP turbine element is acceptable.

DCD Tier 2 Section 10.2.3 also states that the maximum tangential stress resulting from centrifugal forces does not exceed 65 percent of the 0.2 percent offset yield strength at design temperature and speed; or the tangential stresses will not cause a flaw, that is twice the corrected ultrasonic examination reportable size, to grow to critical size in the design life of the rotor. The first criterion is not consistent with the stress limit criterion of SRP 10.2.3, which stipulates that the combined stresses of a low-pressure turbine disk at design overspeed due to centrifugal forces, interference fit, and thermal gradients not exceed 0.75 of the minimum specified yield strength of the material. This is DSER Open Item 10.2.8-3. The second criterion is not consistent with the margin of two between K_{Ic} and applied K mentioned earlier. This issue of inconsistency in the second design criterion is closely related to DSER Open Item 10.2.8-1 and will be resolved under it.

DCD Tier 2 Section 10.2.3.5, "Preservice Tests and Inspections," states that the preservice inspection (PSI) will include a 100 percent volumetric (ultrasonic) examination of each finished machined rotor and a surface visual and magnetic particle examination. Every subsurface ultrasonic indication is either removed or evaluated to ensure that it will not grow in size, and thus compromise the integrity of the turbine during service. All finished machined surfaces are subjected to a magnetic particle examination with no flaw indications permissible in bores or other highly stressed areas. Each turbine rotor assembly is spin tested at 120 percent of rated speed. The proposed preservice tests and inspections, and the acceptance criteria for the examination results are more restrictive than those specified for Class 1 components in ASME Code, Sections III and V. Therefore, they are acceptable to the staff.

DCD Tier 2 Section 10.2.3.6, “Maintenance and Inspection Program Plan,” states that the ISI for the AP1000 turbine assembly includes the disassembly of the turbine and complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, low-pressure turbine blades, and low-pressure and high-pressure rotors. During plant shutdown, turbine inspection will be performed at intervals of approximately 10 years for low-pressure turbines and about 8 years for high-pressure turbines. At least one main steam stop valve, one main steam control valve, one reheat stop valve, and one intercept valve is dismantled and inspected by visual and surface examinations approximately every 3 years during scheduled refueling or maintenance shutdowns. Turbine valve testing is performed at quarterly intervals. In RAI 251.029, the NRC staff requested justification for the inspection and testing intervals for the turbine system and valves. In its response to RAI 251.029, Westinghouse stated that “the turbine inspection interval of assembly and valves is determined based on not only the probability of turbine missile generation but also operating experience of similar equipment and inspection results.” The response further clarifies that the turbine inspection intervals are supported by WCAP-15783 and 15785, while the quarterly testing frequency for valves is supported by WCAP-15785 alone. WCAP-15783 demonstrates that, except for the destructive overspeed mechanism, the probability of turbine missile generation does not exceed 10^{-5} per reactor year even after a running time between inspections of several times longer than 10 years. The NRC staff’s review and acceptance of WCAP-15783, pending resolution of Open Items 3.5.1.3-1 and 3.5.1.3-2, is discussed in Section 3.5.1.3 of this report.

WCAP-15785 complements WCAP-15783 by assessing the total risk of turbine missile ejection at destructive overspeed and at lower overspeeds as a function of valve test interval using detailed nuclear turbine failure data. WCAP-15785 contains detailed information regarding the calculation method for probability of destructive overspeed using historical failure data pertinent to the operating experiences of MHI nuclear steam turbines. The use of this failure data to calculate failure rates for various components is also outlined in the WCAP. The NRC staff’s review determined that the method described above is acceptable because the failure rate calculation methodology for valves and control systems is consistent with the industry practice that has resulted in satisfactory performance and the probability of failure calculation methodology is a bounding approach. WCAP-15785 presents the total probability of turbine missile generation at destructive overspeed as a function of the turbine valve test interval and demonstrates that the probability of turbine missile generation with quarterly valve test is 10^{-5} per reactor-year, less than the NRC criterion of 10^{-4} per reactor-year (as discussed in Section 3.5.1.3 of this report). Hence, the staff finds these inspection intervals acceptable. However, as required by DCD Tier 2 Section 10.2.6 and consistent with the AP600 application, the COL applicant referencing the AP1000 design must submit a turbine maintenance program to the NRC for review and approval within 3 years of obtaining a COL. (Refer to Section 10.5 of this report, COL Action Item 10.5.2.)

10.2.9 Conclusion

Based on the above evaluation, the staff concludes that the design is acceptable and meets the requirements of GDC 4 with respect to the protection of structures, systems, and components important to safety from the effects of turbine missiles. Westinghouse has met these requirements by providing a turbine overspeed protection system to control the turbine action under all operation conditions and which assures that a full-load turbine trip will not cause the turbine to overspeed beyond acceptable limits resulting in turbine missiles.

Pending resolution of DSER Open Items 10.2.8-1, 10.2.8-2, 10.2.8-3 and 3.5.1.3-1, the staff concludes that the integrity of the turbine rotor is acceptable and meets the relevant requirements of GDC 4 of Appendix A of 10 CFR Part 50. This conclusion is based upon Westinghouse demonstrating that its design meets the requirements of GDC 4 with respect to the use of materials with acceptable fracture toughness, adequate design, and the requirements for preservice and ISIs. Westinghouse has also described its program for assuring the integrity of LP turbine rotors, which include the use of suitable materials of adequate fracture toughness, conservative design practices, preservice and inservice inspection and valve testing. This provides reasonable assurance that the probability of failure with missile generation is low during normal operation, including transients up to design overspeed.

10.3 Main Steam Supply System

10.3.1 Main Steam Supply System

The staff reviewed the design of the main steam supply system (MSSS) in accordance with Section 10.3 of the SRP. Acceptability of the design of the MSSS is based on meeting the following:

- GDC 4, "Environmental and dynamic effects design bases," with respect to safety-related portions of the system being capable of withstanding the effects of external missiles and internally-generated missiles, pipe whip, and jet impingement forces associated with pipe breaks;

- GDC 5, "Sharing of structures, systems, and components," as related to the capability of shared systems and components important to safety to perform required safety functions;

- GDC 34, "Residual heat removal," as related to the system function of transferring residual and sensible heat from the reactor system in indirect cycle plants; and the guidance found in the following:

  The system is designed in accordance with the positions in Branch Technical Position RSB 5-1 as related to the design requirements for residual heat removal.

  The system is designed to NUREG-0138, Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976, Memorandum From Director, NRR, to NRR Staff, Issue Number 1, which specifies allowable credit being taken for valves downstream of the main steam isolation valve (MSIV) to limit blowdown of a second steam generator in the event of a steamline break upstream of the MSIV.

The MSSS includes components of the AP1000 steam generator system (SGS), main steam system (MSS), and main turbine system (MTS). The function of the MSSS is to transport steam from the steam generators to the high-pressure turbine over the entire operating range. The system provides steam to the moisture separator/reheater and the steam seal system for the main turbine. The system removes heat generated by the NSSS by means of a steam dump to the condenser through the turbine bypass system or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves, when either the turbine generator or condenser is unavailable.

DCD Tier 2 Section 10.3.1.1 and DCD Tier 2 Table 3.2-3, steam generator system (SGS), identify all the safety-related mechanical equipment in the MSSS and lists the associated ASME Code class. The following MSSS components are classified as safety-related:

- the main steamline piping from the steam generator up to the pipe restraint located on the wall between the auxiliary building and the turbine building, including main steam isolation valve and main steam isolation bypass valves.

- the inlet piping from the main steamline up to the main steam safety valve discharge piping and vent stacks, and to power-operated relief line piping, including block valve and power-operated relief valves.

- the instrumentation tubing up to, and including, the main steamline pressure instrument root valves.

- the vent line and nitrogen connection on the main steamline up to, and including, the first isolation valve.

- the main steam drain condensate pot located upstream of the main steam isolation valves, and the drain piping up to, and including, the first isolation valve.

- the condensate drain piping from the outlet of the isolation valve to the restraint on the wall between the auxiliary building and the turbine building.

The remainder of the MSSS is non-safety-related.

As stated in the DCD, the safety-related portion of the MSSS complies with the QA requirements of Appendix B to 10 CFR Part 50 and is designed to environmental design and fire protection requirements as discussed in DCD Tier 2 Sections 3.11 and 9.5 respectively. Also, the DCD states that no single failure coincident with loss of offsite power comprises the MSSS's safety functions.

Provision III.5.f of SRP Section 10.3 states that in a postulated safe-shutdown earthquake, the design includes the capability to operate atmospheric dump valves remotely from the control room so that cold shutdown can be achieved using only safety-grade components, assuming a concurrent loss of offsite power. In the AP1000 design, the passive residual heat removal (RHR) system (see Section 5.4.14 of this report), which can be initiated automatically without requiring the control of steamline pressure, provides safety-grade decay heat removal capability. The power-operated atmospheric relief valves provide a non-safety-related means for plant cooldown to the point that the normal residual heat removal system can be initiated to remove the decay heat. The relief valves are automatically controlled by steamline pressure, with remote manual adjustment of the pressure setpoint from the control room. If the relief valve for an individual main steamline is unavailable because of the loss of its control or power supply, the respective spring-loaded safety valves, which are safety-related, will provide overpressure protection. The safety valves are designed to AP1000 Class B; ASME Code, Section III, Class 2; and seismic Category I. Therefore, the staff concludes that the position in Branch Technical Position RSB 5-1 as related to the design requirements for residual heat removal is met.

Following a main steamline break, the main steam isolation is designed to limit blowdown to one steam generator so that the fuel design limits and containment design pressure can be maintained. The main steam isolation valves (MSIVs) and MSIV bypass valves on each main steamline are designed to isolate the secondary side of the steam generators to prevent the uncontrolled blowdown of more than one steam generator and isolate non-safety-related portions of the system. The MSIV automatically closes upon receipt of either of two main steam isolation signals associated with independent Class 1E electrical divisions. Redundant power supplies and power divisions operate the MSIVs and MSIV bypass valves. The isolation valve is a part of the containment isolation boundary and therefore is specified as Class 1E, active, ASME Code, Section III, Safety Class 2. The conditions that initiate automatic closure of the MSIVs and MSIV bypass valves are high containment pressure, low steamline pressure, high steamline pressure negative rate, and low reactor coolant inlet temperature. The MSIVs are gate valves controlled by a pneumatic/hydraulic operator. The energy required to close the valves is stored in the form of compressed nitrogen in one end of the actuator cylinder. The valves are maintained open by high-pressure hydraulic fluid. For emergency closure, redundant Class 1E solenoids are energized, causing the high-pressure hydraulic fluid to be dumped to a fluid reservoir and the valves to close. The backup isolation valves (such as the turbine stop valves) receive signals derived from the protection and safety monitoring system (PMS) to actuate the valves.

In DCD Tier 2 Section 3.6.1.1, the applicant states that turbine stop valves, moisture separator/reheater stop valves, and turbine bypass valves (which are not safety-related) are credited in single-failure analyses to mitigate postulated steamline ruptures. These valves are included as non-safety-related equipment, and are evaluated for pipe whip protection as part of the evaluation of the affected system as required by GDC 4. Based on the design alternatives identified in Issue No. 1 of NUREG-0138, relative to utilizing the turbine stop valves to provide redundancy for safety-related equipment, the turbine stop valves and control valves are credited for demonstrating that the design will preclude the blowdown of more than one steam generator, assuming a concurrent single active failure. The staff concluded in NUREG-0138 that in accidents involving spontaneous failures of secondary system piping, reliance on non-safety-grade valves in the postulated accident evaluation is permitted based on the reliability of these valves. Technical specification (TS) control for the turbine stop valves, moisture separator reheater stop valves, and turbine bypass valves is as a part of the MSIV TS. Based on the conclusion in NUREG-0138, the staff finds that the AP1000 MSSS meets the requirements of GDC 34 as related to limiting blowdown of a second steam generator in the event of a steamline break upstream of the MSIV.

Based on meeting the relevant acceptance criteria specified in the SRP, the staff concludes that the MSSS meets the requirements of GDC 34 as related to the system function of transferring residual and sensible heat from the reactor system.

Compliance with GDC 2, “Design bases for protection against natural phenomena,” is based on meeting the relevant acceptance criteria specified in the SRP that the safety-related portions of the system are capable of withstanding the effects of natural phenomena such as earthquakes, tornados, hurricanes, and floods, and meet the positions of Regulatory Guide 1.29," Seismic Design Classification" as related to the seismic design classification of system components, and Regulatory Guide 1.117, "Tornado Design Classification" as related to the protection of structures, systems, and components important to safety from the effects of tornado missiles.

AP1000 piping and valves from the steam generators up to and including each MSIV, are designed in accordance with ASME Code, Section III, Class 2, and seismic Category I requirements, as are branch lines up to and including the first valve (including a safety or relief valve) that is either normally closed or capable of automatic/remote manual closure. Piping and valves downstream of the MSIVs and the valves identified above are designed in accordance with ASME Code, Section III, Class 3, and seismic Category, I up to and including pipe anchors located at the auxiliary building wall. The power supplies and controls necessary for safety-related functions of the MSSS are Class 1E.

In DCD Tier 2 Sections 10.3.1.1 and 10.3.3, the applicant stated that the safety-related portion of the system is designed to withstand the effects of a safe shutdown earthquake, is protected from the effects of natural phenomena, and is capable of performing its intended function following postulated events. The safety-related portion of the MSSS is located in the containment and auxiliary buildings, which are designed to withstand the effects of earthquakes, tornados, hurricanes, floods, external missiles, and other appropriate natural phenomena. The components of the safety-related MSSS are qualified to function in normal, test, and accident environmental conditions. The staff evaluation of flood protection is described in Section 3.4.1 of the this report. The safety-related mechanical equipment in the main steam supply system is identified in DCD Tier 2 Table 3.2-3 and described in DCD Tier 2 Section 10.3.1.1. Based on the review, the staff concludes that the safety-related portion of the system meets the requirements of GDC 2, "Design bases for protection against natural phenomena," of Appendix A to 10 CFR Part 50 with respect to the ability of structures housing the safety-related portion of the system and the safety-related portions of the system being capable of withstanding the effects of natural phenomena.

Compliance with GDC 4 is based on meeting the relevant requirements specified in the SRP that the safety-related portions of the system are capable of withstanding the effects of external missiles, internally-generated missiles, pipe whip, and jet impingement forces associated with pipe breaks and Position C.1 of Regulatory Guide (RG) 1.115, Protection Against Low-Trajectory Turbine Missiles, dated July 1977 (as related to the protection of SSCs important to safety from the effects of turbine missiles). In addition, the SRP states that the system design should adequately consider steam hammer and relief valve discharge loads to assure that system safety functions can be achieved and should assure that operating and maintenance procedures include adequate precautions to avoid steam hammer and relief valve discharge loads. The system design should also include protection against water entrainment.

Steam hammer prevention is addressed by appropriate precautions in the operating and maintenance procedures, which include system operating procedures that caution against using the MSIVs except when necessary, and operating and maintenance procedures that emphasize proper draining. Westinghouse also stated that the stress analyses for the safety-related portion of the MSSS piping and components include the dynamic loads from rapid valve actuation of the MSIVs and the safety valves. Design features that prevent water formations in the MSSS include the use of drain pots and the proper sloping of lines.

A discussion of high-energy pipe break locations and evaluation of effects is provided in DCD Tier 2 Sections 3.6.1 and 3.6.2, including pipe whip and jet impingement forces associated with pipe breaks. DCD Tier 2 Section 10.3.2.2.1 states that the main steamlines between the steam generator and the containment penetration are designed to leak-before-break (LBB). A discussion of the LBB application and criteria is presented in DCD Tier 2 Section 3.6.3. The staff evaluation is in Sections 3.6.1 through 3.6.3 of the DSER. The main steamline leak detection system is included in the plant TSs as TS 3.7.8, “Main Steamline Leakage.”

An evaluation of the protection against externally and internally-generated missiles is provided in Section 3.5 of this report. The staff's finding on the conformance with GDC 4 is discussed in Sections 3.5 and 3.6 of this report.

Although the AP1000 design can be used at either single-unit or multiple-unit sites, Westinghouse stated in DCD Tier 2 Section 3.1.1 that the AP1000 design is a single-unit plant and 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 COL applicant must 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 described above, the staff has reviewed the MSSS in accordance with Section 10.3 of the SRP and finds that the system design conforms with the Commission regulations given in GDC 2, 4, 5, and 34. Therefore, the design of MSSS is acceptable.

10.3.2 Steam and Feedwater System Materials

The staff reviewed DCD Tier 2 Section 10.3.6, "Steam and Feedwater System Materials," in accordance with Section 10.3.6, "Steam and Feedwater System Materials," of the SRP. The materials selection, fabrication, and fracture toughness of ASME Code Class 2 and 3 pressure boundary components in the steam and feedwater system are acceptable if they meet the relevant requirements of 10 CFR 50.55a, “Codes and Standards;” 10 CFR Part 50, Appendix A, GDC 1, “Quality Standards and Records,” and GDC 35, “Emergency Core Cooling System;” and 10 CFR Part 50 Appendix B, “Quality Assurance Criteria.”

GDC 1 requires, in part, 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 functions to be performed. This requirement is satisfied when the requirements of 10 CFR 50.55a are met.

GDC 35 requires, in part, that suitable interconnection, leak detection, isolation, and containment capabilities be provided to assure the safety system function (i.e. emergency core cooling) can be provided assuming a single failure. For ferritic pressure retaining components of a critical nature, the containment capability, is assured, in part, by requiring minimum fracture toughness performance of the materials of which they are fabricated.

The requirements of 10 CFR Part 50, Appendix B, establish QA requirements for the design, construction, and operation of SSCs that are important to safety.

The specific acceptance criteria necessary to meet these requirements are as follows:

- Fracture toughness of Class 2 and 3 Components: The fracture toughness properties of the ferritic materials of these components is acceptable if it meets requirements of NC-2300, “Fracture Toughness for Materials (Class 2)” and ND-2300, “Fracture Toughness for Materials (Class 3)” of the ASME Code, Section III.

- Materials Selection and Fabrication: The materials specified for use in Class 2 and 3 components are acceptable if they conform to Appendix I of Section III of the ASME Code, and to Parts A, B, and C of Section II of the Code. Materials acceptable to the staff are also specified in RG 1.85, “Materials Code Case Acceptability, ASME Section III Division 1.”

- The materials specified for use in Class 2 and 3 components are acceptable if the regulatory positions of RG 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," are met. This guide describes methods acceptable to the staff for prevention of intergranular stress corrosion cracking (IGSCC)of austenitic stainless steel and nickel-based alloy components.

- The materials specified for use in Class 2 and 3 components are acceptable provided the acceptance criteria of ASME Section III, paragraphs NB/NC/ND 2550 through 2570 for nondestructive examination of tubular products are followed.

- Welding Criteria applicable to Class 2 and 3 components: The materials specified for use in Class 2 and 3 components are acceptable if welds in locations of restricted direct and visual accessibility are welded by personnel qualified per the regulatory positions of RG 1.71, " Welder Qualification for Areas of Limited Accessibility." This guide describes methods acceptable to the staff for providing better control of welder technique in production welding.

DCD Tier 2 Section 10.3.6, "Steam and Feedwater System Materials," indicates the material specifications for pressure retaining materials in the safety-related portions of the main steam and feedwater systems meet the fracture toughness requirements of the ASME Code, Section III, Articles NC-2300 and ND-2300, for Quality Group B and Quality Group C components. Pipe, flanges, fittings, valves, and other piping material conform to the referenced ASME, American Society for Testing and Materials (ASTM), American National Standards Institute (ANSI), or Manufacturer Standardization Society-Standard Practice code. No copper or copper-bearing materials are used in the steam and feedwater system. Materials selection and fabrication requirements for ASME Code Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems are consistent with the requirements for ASME Class 2 and 3 systems and components outlined in DCD Tier 2 Sections 6.1.1.1 and 6.1.1.2 for engineered safety feature (ESF) components. Material specifications for the main steam and feedwater systems are listed in DCD Tier 2 Table 10.3.2-3. Conformance with the applicable RGs is described in DCD Tier 1 Section 1.91. Nondestructive inspection of ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems is addressed in DCD Tier 2 Section 6.6.5.

The staff evaluation of Main Steam and Feedwater materials is divided into the following three sections: fracture toughness, material selection and fabrication, and nondestructive inspection.

- Fracture toughness: DCD Tier 2 Section 10.3.6.1 indicates that the fracture toughness properties of the materials of the Main Steam and Feedwater systems will meet the requirements of the ASME Code, Section III, Articles NC-2300 and ND-2300 for Quality Group B and C components, respectively. The fracture toughness requirements of the Code provide reasonable assurance that the materials will have adequate margins against the possibility of nonductile behavior or rapidly propagating fracture. This satisfies, in part, the requirements of 10 CFR 50.55a, GDC 1, and GDC 35.

- Material Selection and Fabrication: Carbon steel piping in steam and feedwater systems has experienced wall thinning due to the single-phase or two-phase erosion-corrosion. DCD Tier 2 Section 10.1.3 indicates that erosion-corrosion resistant materials are used in steam and power conversion systems for components exposed to single-phase or two-phase flow where significant erosion can occur. Westinghouse stated that factors considered in the evaluation of erosion-corrosion include system piping and component configuration and geometry, water chemistry, piping and component material, fluid temperature, and fluid velocity. In addition to material selection, pipe size and layout may also be used to minimize the potential for erosion-corrosion in systems containing water or two-phase flow. Carbon steel with only carbon and manganese alloying agents will not be used for applications subject to erosion-corrosion. In addition, the steam and feedwater systems are designed to facilitate inspection and erosion-corrosion monitoring programs. Pipe wall thickness inspections will be performed by the COL applicant to monitor the presence of excessive wall thinning.

  An industry sponsored computer program developed for nuclear and fossil power plant applications is used to evaluate the rate of wall thinning for components and piping potentially susceptible to erosion-corrosion. The engineering models are the result of research and development in the fields of material science, water chemistry, fluid mechanics, and corrosion engineering. The COL holder will address preparation of an erosion-corrosion monitoring program for carbon steel portions of the steam and power conversion systems that contain water or wet steam. This monitoring program will address industry guidelines and the provisions included in GL 89-09, “Erosion/Corrosion-Induced Pipe Wall Thinning.” This is a COL Action Item 10.3.2.1.

  DCD Tier 2 Section 10.3.6.2 indicates material selection and fabrication requirements for ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems are consistent with the requirements for ASME Class 2 and 3 components or with the staff positions in RG 1.85. Since the materials meet the criteria of SRP 10.3.6 and since erosion/corrosion is addressed by selection of resistant materials and by inservice monitoring, the applicable requirements of GDC 1 are satisfied and, thus, the staff finds the material selection acceptable.

- DCD Tier 2 Section 10.3.6.2 indicates conformance with applicable RGs is described in DCD Tier 2 Section 1.9.1. The staff noted that in DCD Tier 2 Appendix 1A, "Compliance with Regulatory Guides," the applicant states that the AP1000 design provides and alternative to RG 1.71, Welder Qualification for Areas of Limited Accessability." The staff evaluation of this alternative is contained in Section 5.2.3 of this report. DCD Tier 2 Section 1.9.1 indicates that the AP1000 design will comply with RG 1.37 with respect to prevention of IGSCC in components fabricated from austenitic stainless steel and nickel-based alloys. Since the AP1000 design conforms with with these RGs the applicable requirements of GDC 1 and 10 CFR 50, Appendix B, are satisfied.

- Nondestructive Inspection: DCD Tier 2 Section 10.3.6.2 indicates nondestructive inspection of ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the Main Steam and Feedwater systems is addressed in DCD Tier 2 Section 6.6.5. DCD Tier 2 Section 6.6 indicates that the ASME Code, Section III, rules for fabrication examinations will be followed. This section of the DCD is evaluated in Section 6.6 of this report. Therefore, the fabrication of the materials specified for use in Class 2 and 3 components will comply with the acceptance criteria of ASME Section III, paragraphs NB/NC/ND 2550 through 2570 for nondestructive examination of tubular products. These criteria are in accordance with SRP 10.3.6, and satisfy, in part, the requirements of 10 CFR 50.55a and GDC 1 and are, therefore, acceptable to the staff.

The staff concludes that the AP1000 steam and feedwater system materials will be acceptable since they meet the acceptance criteria of SRP 10.3.6, and satisfy the applicable requirements of 10 CFR 50.55a; 10 CFR Part 50, Appendix A, GDC 1 and 35; and 10 CFR Part 50, Appendix B.

10.4 Other Features

10.4.1 Main Condenser

The staff reviewed the design of the main condenser in accordance with Section 10.4.1 of the SRP. The acceptability of the system design is contingent on meeting the requirements of GDC 60, “Control of releases of radioactive materials to the environment,” as it relates to system design such that failures do not result in excessive releases of radioactivity to the environment, do not cause unacceptable condensate quality, and do not flood areas housing safety-related equipment.

The AP1000 design main condenser system is described in DCD Tier 2 Section 10.4.1 and shown in DCD Tier 2 Figure 10.4.7-1. Design parameters of the condenser (such as heat transfer capability, surface area, design operating pressure, shell side pressure, circulating water flow, tube side inlet temperature, tube-side temperature rise, condenser outlet temperature, condenser tube material, and so forth) were listed in DCD Tier 2 Table 10.4.1-1, "Main Condenser Design Data."

The main condenser system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine system. When the system functions as the steam cycle heat sink, it receives and condenses exhaust steam from the main turbine and the turbine bypass system. The main condenser is designed to receive and condense the full-load main steam flow exhausted from the main turbine and serves as a collection point for vents and drains from various components of the steam cycle system. Upon actuation of the turbine bypass system, the main condenser is designed to receive and condense steam bypass flows of up to 40 percent of plant full load steam flow without either reaching the condenser over-pressure turbine trip setpoint or exceeding the allowable exhaust temperature. In the event of high condenser pressure or a trip of both circulating water pumps, the turbine bypass valves are prohibited from opening. If the main condenser is unavailable to receive this flow, the steam is discharged to the atmosphere through the main steam power-operated relief valves or spring-loaded safety valves.

The main condenser is a non-safety-related and non-seismic component located in the turbine building. The failure of the main condenser and the resultant flooding will not preclude operation of any essential system, because no safety-related equipment is located in the turbine building, and the water cannot reach safety-related equipment located in Category 1 plant structures. Therefore, the staff finds GDC 60 is met with respect to failures not flooding areas housing safety-related equipment.

The main condenser has no significant inventory of radioactive contaminants during normal operation and plant shutdown. Radioactive contaminants can be obtained through primary-to-secondary system leakage resulting from steam generator tube leaks. Early detection of concentrated levels of radioactivity is provided by the MSSS and steam generator blowdown system (BDS) radiation devices. In addition to this monitoring, radioactive effluent monitoring equipment is provided in the turbine island vents, drains, and relief system (TDS) at the combined exhaust of the condenser air removal system (CMS) and the turbine gland seal system (GSS). The plant operator may secure the discharge of the radioactive effluent upon detection of a high radioactivity level. Although the design has radioactivity monitors in the system to detect leakage into and out of the main condenser during normal operation, startup, and shutdown, the main condenser has no radioactive contaminants inventory. Because the above systems continuously monitor and detect the radioactivity leakage into and out of the condenser, GDC 60 is met with respect to failures in the system design that could result in excessive releases of radioactivity to the environment. The radiological monitoring capabilities are discussed in Section 11.5 of this report.

The main condenser is not subject to ISI testing. The condenser water boxes are hydrostatically tested after erection. Condenser shells are tested by the fluorescent tracer method in accordance with ASME Power Test Code 19.11. Tube joints are leak tested during construction and prior to startup.

The system is provided with the following instrumentation and control features that determine and verify the proper operation of the main condenser:

- the main condenser hotwell level control devices,
- control room indicators and alarms of water levels in the condenser hotwell,
- control room indicators and alarms of condenser pressure,
- a turbine trip on high turbine exhaust pressure, and
- temperature indicators for monitoring condenser performance.

The main condenser interfaces with the secondary sampling system to permit sampling of the condensate in the hotwell to determine in-leakage from the circulating water system. Also, each tube sheet is provided with a grab sampling capability. This information helps to identify the leaking tube bundle. The steps that may be taken are, first isolate the circulating water system from the affected water box while at reduced plant power, then drain the water box and finally repair or plug the affected tubes.

The condensate polishing system removes corrosion products and ionic impurities from the condensate system. This allows for continued operation with a "continuous" condenser tube leakage of 0.004 L/min (0.001 gpm) or a "faulted" leak of 0.4 L/min (0.1 gpm) until repairs can be made or until an orderly shutdown is achieved. Secondary cycle chemistry guidelines are located in DCD Tier 2 Table 10.3.5-1. DCD Tier 2 Subsection 10.3.5.5 discusses action levels for abnormal secondary cycle chemistry. Therefore, the staff finds GDC 60 is met with respect to failures not causing unacceptable condensate quality.

As discussed above, the staff reviewed the design of the main condenser in accordance with Section 10.4.1 of the SRP. On the basis of this review, the staff concludes that the main condenser system is acceptable and meets the requirements of GDC 60 with respect to the system design such that failures do not result in excessive releases of radioactivity to the environment. Westinghouse meets this requirement by providing radioactive monitors in the system to detect leakage into and out of the main condenser.

10.4.2 Main Condenser Evacuation System

Main condenser evacuation is performed by the CMS. The staff reviewed the design of the CMS in accordance with Section 10.4.2 of the SRP. Acceptability of the design of the CMS is based on meeting the following general design criteria as described in the SRP:

- GDC 60, as it relates to the CMS design for the control of releases of radioactive materials to the environment.

- GDC 64, “Monitoring radioactivity releases,” as it relates to the CMS design for the monitoring of releases of radioactive materials to the environment.

The SRP includes RG 1.33 and RG1.123 in the acceptance criteria. The requirements of the two Commission regulations may be met by using the regulatory positions contained in the following RGs and industrial standards:

- Regulatory Guide 1.26, “Quality Group Classifications and Standards for Water,-Steam-, and Radioactive -Waste-Containing Components of Nuclear Power Plants,” as it relates to the CMS quality group classification that may contain radioactive materials but is not part of the reactor coolant pressure boundary and is not important to safety.

- RGs 1.33, “Quality Assurance Program Requirements (Operation),” and Regulatory Guide 1.123, “Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants,” as they relate to the QA programs for the CMS components that may contain radioactive materials.

- "Standards for Steam Surface Condensers," 6th Ed., 1979, Heat Exchanger Institute, as it relates to the CMS components that may contain radioactive materials.

The CMS is a non-safety-related system located in the turbine building. All piping is designed to ANSI B31.1 and, consistent with the guidance in RG 1.26, the CMS is in Quality Group D as listed in DCD Table 3.2-3. Using liquid ring vacuum pumps, the system establishes and maintains a vacuum in the condenser during startup and normal operation. It also removes non-condensable gases and air from the main condenser during plant startup, cooldown, and normal operation from the two condenser shells and exhausts them into the atmosphere.

Westinghouse indicated in WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," that the CMS will be in conformance with 8th edition of "Standards for Steam Surface Condensers, Heat Exchanger Institute." In DCD Tier 2 Section 10.4.2.4, Westinghouse stated that a performance test will be conducted on each pump in accordance with the "Heat Exchanger Institute Performance Standard for Liquid Ring Vacuum Pumps."

WCAP-15799 stated that RG 1.33 is not applicable, and that RG 1.123 has been withdrawn. RG 1.33, "Quality Assurance Program Requirements (Operation)," applies only to the operational phase of nuclear power plants. Therefore, the staff will review COL applications to ensure their conformance with RG 1.33 or an acceptable alternative. A COL applicant referencing the AP1000 certified design should demonstrate compliance with RG 1.33 or an acceptable alternative. Westinghouse includes this COL action as a part of the overall plant QA program for operation, which is discussed in DCD Tier 2 Section 17.4. This approach in dealing with QA for operation is similar to the approach taken for QA in the radwaste systems (see Section 11.2 and 11.3 of this report) because radioactive contaminants can be introduced in the CMS through primary-to-secondary system leakage resulting from steam generator tube leakage. The staff agrees with Westinghouse that RG 1.123 has been withdrawn and is not applicable to the AP1000 CMS.

Provisions 3 and 5 of the specific acceptance criteria in the SRP recommend a discussion on the potential for explosive mixtures and provide specific guidance for the system if the potential exists. DCD Tier 2 Section 10.4.2.2.1 states that the potential for explosive mixtures within the CMS does not exist.

Early detection of concentrated levels of radioactivity is provided by the MSSS and steam generator BDS radiation devices. In addition to this monitoring, radioactive effluent monitoring equipment is provided in the TDS at the combined exhaust of the CMS and the GSS. The plant operator may secure the discharge of the radioactive effluent upon detection of high radioactivity level. Although the design has radioactivity monitors in the system to detect leakage into and out of the main condenser during normal operation, startup, and shutdown, the main condenser has no radioactive contaminants inventory. Radioactive contaminants can only be obtained through primary-to-secondary system leakage resulting from steam generator tube leaks. Because the above systems continuously monitor and detect the radioactivity leakage into and out of the condenser and the operator can control the discharge, GDC 60 and GDC 64 are met with respect to the control and monitoring radioactivity releases to the environment. The radiological monitoring capabilities are discussed in Section 11.5 of this report.

As discussed above, the staff reviewed the design of the CMS in accordance with Section 10.4.2 of the SRP, and finds the system conforms with the Commission regulations given in GDC 60 and GDC 64 and is therefore acceptable.

10.4.3 Turbine Gland Seal System

The staff reviewed the design of the gland seal system (GSS) in accordance with Section 10.4.3 of the SRP, "Turbine Gland Sealing System." Acceptability of the design of the GSS is based on meeting the following general design criteria as described in the SRP:

- GDC 60 as it relates to the GSS design for the control of releases of radioactive materials to the environment.

- GDC 64 as it relates to the GSS design for the monitoring of releases of radioactive materials to the environment.

The SRP includes RG 1.33 and RG1.123 in the acceptance criteria. The requirements of the two Commission regulations may be met by using the regulatory positions contained in the following RGs and industrial standards:

- Regulatory Guide 1.26, “Quality Group Classifications and Standards for Water,-Steam-, and Radioactive -Waste-Containing Components of Nuclear Power Plants,” as it relates to the CMS quality group classification that may contain radioactive materials but is not part of the reactor coolant pressure boundary and is not important to safety.

- RGs 1.33, “Quality Assurance Program Requirements (Operation),” and Regulatory Guide 1.123, “Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants,” as they relate to the QA programs for the CMS components that may contain radioactive materials.

The GSS is a non-safety-related system designed to prevent air leakage into and steam leakage out of the casings of the turbine generator. The system returns condensed steam to the condenser and exhausts non-condensable gases into the atmosphere. The system is designed to detect the presence of radioactive contamination in the gas exhaust. The system consists of a steam supply header, steam drains/non-condensable gas exhaust header, two motor-driven gland steam condenser blowers, gland seal condenser, vent and drain lines, and associated piping, valves, and controls. The GSS serves no safety-related function and consistent with the guidance in RG 1.26, the GSS is in the Quality Group D as listed in DCD Table 3.2-3.

During the initial startup phase of turbine generator operation, steam is supplied to the GSS from the auxiliary steam header supplied from the auxiliary boiler. At times other than initial startup, GSS steam is supplied from either the auxiliary steam system or from main steam. The system is tested in accordance with written procedures during the initial testing and operation program. The testing procedures for the system are provided by the turbine vendor in equipment instruction manuals. During normal operation, the satisfactory operation of the system components will be demonstrated by monitoring essential parameters. Pressure and temperature indication with alarms are provided for monitoring the operation of the system. A pressure controller is provided to maintain steam-seal header pressure by providing signals to the steam-seal feed valve. The gland seal condenser is monitored for shell side pressure and internal liquid level. A radiation detector with an alarm is provided in the TDS.

WCAP-15799 stated that RG 1.33 is not applicable, and that RG 1.123 has been withdrawn. RG 1.33 applies only to the operational phase of nuclear power plants. Therefore, the staff will review COL applications to ensure their conformance with RG 1.33 or an acceptable alternative. A COL applicant referencing the AP1000 certified design should demonstrate compliance with RG 1.33 or an acceptable alternative. Westinghouse includes this COL Action as a part of the overall plant QA program for operation, which is discussed in DCD Tier 2 Section 17.4. This approach in dealing with QA for operation is similar to the approach taken for QA in the radwaste systems (see Section 11.2 and 11.3 of this report) because radioactive contaminants can be introduced in the GSS through primary to secondary system leakage resulting from steam generator tube leakage. The staff agrees with Westinghouse that RG 1.123 has been withdrawn and is not applicable to the AP1000 GSS.

The mixture of non-condensable gases discharged from the gland steam condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage as a result of a steam generator tube leak, it is possible for the mixture discharged to be radioactively contaminated. The discharge line vents to the TDS, which contains a radiation monitor for the detection of radioactivity. Upon detection of unacceptable levels of radiation, operating procedures are implemented. The radiological monitoring capabilities are discussed in Section 11.5 of this report. Because the above systems continuously monitor and detect the radioactivity and operating procedures may be implemented to control unacceptable levels of radiation, GDC 60 and GDC 64 are met with respect to the control and monitoring radioactivity releases to the environment.

As discussed above, the staff reviewed the design of the GSS in accordance with Section 10.4.3 of the SRP. The system conforms with the Commission regulation given in GDC 60 and GDC 64, and is therefore acceptable.

10.4.4 Turbine Bypass System

The staff reviewed the design of the turbine bypass system in accordance with Section 10.4.4 of the SRP. The acceptability of the system design is based on meeting the requirements of GDC 4 and GDC 34 as described in the SRP:

- GDC 4, as it relates to the system being designed such that a failure of the system (due to a pipe break or system malfunction) does not adversely affect safety-related systems or components.

- GDC 34, as it relates to the ability to use the turbine bypass system for shutting down the plant during normal operations by removing residual heat without using the turbine generator.

The turbine bypass system, which is also called the steam dump system, provides the capability to direct main steam from the steam generators bypassing the turbine to the main condenser in a controlled manner to dissipate heat and to minimize transient effects on the RCS during startup, hot shutdown, cooldown, and step-load reductions in generator loads.

The turbine bypass system consists of a manifold connected to the main steamlines upstream of the turbine stop valves and lines from the manifold with regulating valves to each condenser shell. The turbine bypass valves are globe valves and are electro-pneumatically operated. The bypass valves will fail to a closed position upon loss of air or electrical signal. A modulating position responds to the electrical signal from the control system and provides the appropriate air pressure to the valve actuator for modulating the valves open.

Solenoid valves located in the air line to each bypass valve actuator open and close the bypass valve and serve as protective interlocks for bypass valve actuation for tripping the valve open or closed. Two of the blocking solenoid valves for each turbine bypass valve are redundant and prevent bypass valve actuation upon low RCS average temperature (T_{avg}). This minimizes the possibility of excessive RCS cooldown. However, the low T_{avg} block can be manually bypassed for two of the bypass valves to allow operation during plant cooldown. Another blocking solenoid valve prevents actuation of the bypass valve when the condenser is not available.

The turbine bypass system has two modes of operation (1) T_{avg} control and (2) pressure control modes. A discussion of the system operation is in DCD Tier 2 Section 10.4.4.3. The design basis of the turbine bypass system is to eliminate challenges to the main steam power-operated relief valves, main steam safety valves, and pressurizer safety valves during a reactor trip from 100 percent power or a 100 percent load rejection, or turbine trip from 100 percent power without a reactor trip. The turbine bypass system meets its power generation design basis with its ability to bypass 40 percent of the full load main steam flow to the main condenser. The system's total flow capacity, in combination with bypass valve response time, RCS design, and reactor control system response is sufficient to meet its design basis.

For load rejections greater than 10 percent but less than 50 percent, or a turbine trip from 50 percent power or less, the turbine bypass system operates with the NSSS control systems to meet the design-basis requirements for heat removal. For power changes less than or equal to a 10 percent change in electrical load, the turbine bypass system is not actuated. The total power change is handled by the power control, pressurizer level and pressure control, and the steam generator level control systems. Therefore, the staff concludes that the system is designed to enable sufficient steam to be bypassed to the main condenser so that the plant can be shutdown during normal operation without using the turbine generator. The system therefore meets GDC 34, "Residual Heat Removal," of Appendix A to 10 CFR Part 50 with respect to the ability to use the system for shutting down the plant during normal operations.

In DCD Tier 2 Section 10.4.4.5, Westinghouse stated that the turbine bypass valves will be tested for operability and the system will by hydrostatically tested to confirm leak tightness before the turbine bypass system is placed in service. The bypass valves may be tested while the unit is in operation. System piping and valves are accessible for inspection. The turbine bypass system except for the turbine bypass valves does not require ISI and testing.

The failure of a turbine bypass high-energy line will not disable the turbine speed control system. The turbine speed control system is designed such that its failure will cause a turbine trip. If the bypass valves fail open, an additional heat load is placed on the condenser. If this load is great enough, the turbine is tripped on high condenser pressure. Ultimate over-pressure protection for the condenser is provided by turbine rupture discs. If the bypass valves fail closed, the power-operated relief valves permit a controlled cooldown of the reactor. DCD Tier 2 Chapter 15 addresses credible single failures of the turbine bypass system on the NSSS.

The high-energy lines of the turbine bypass system are located in the turbine building, which is a non-seismic category building. No safety-related equipment is located within the turbine building or near the turbine bypass system. Therefore, the staff concludes that the system complies with the requirements of GDC 4 regarding adverse effects of a pipe break or malfunction on those components of the system necessary for shutdown or accident prevention or mitigation, as there are no such systems in the turbine building.

The turbine bypass system includes all components and piping from the branch connection at the main steam system to the main condensers. The scope of review of the turbine bypass system for the AP1000 design included layout drawings, piping and instrumentation drawings (P&IDs), and descriptive information for the turbine bypass system and auxiliary supporting systems that are essential to its operation.

The basis for acceptance of the turbine bypass system is conformance of the design, design criteria, and design bases to the Commission's regulations as set forth in GDC 4 and 34 of Appendix A to 10 CFR Part 50 as follows:

- Westinghouse meets the requirements of GDC 4 with respect to the system being designed, such that a safe shutdown will not be prevented as a result of the turbine bypass system failure.

- Westinghouse meets the requirements of GDC 34 with respect to the ability to use the turbine bypass system for shutting down the plant during normal operations. The turbine bypass system is designed such that sufficient steam can be bypassed to the main condenser so that the plant can be shutdown during normal operations without using the turbine generator.

Based on the above, the staff concludes that the design of the turbine bypass system conforms to Section 10.4.4 of the SRP and meets the requirements of GDC 4 and GDC 34.

10.4.5 Circulating Water System

The staff reviewed the circulating water system (CWS) in accordance with Section 10.4.5, of the SRP. Acceptability of the system as described in the DCD is based on meeting the requirements of GDC 4, as it relates to design provisions provided to accommodate the effects of discharging water that may result from a failure of a component or piping in the CWS. Compliance with GDC 4 is based on meeting the relevant acceptance criteria specified in the SRP, such as the following:

- means to prevent, detect, and control flooding of safety-related areas due to leakage from the CWS.

- means to preventadverse effects of malfunction or failure of CWS piping on functional capabilities of the safety-related systems or components.

- control of water chemistry, corrosion, and organic fouling in the CWS.

The CWS is a non-safety-related system that is designed to provide a continuous cooling water supply to the main condenser, the turbine building closed cooling water system (TCS) heat exchangers, and the condenser vacuum pump seal water heat exchangers under all modes of power operation and design weather conditions. The system consists of three

$33^{1}/_{3}$-percent-capacity circulating water (CW) pumps (mounted in an intake structure), one hyperbolic natural-draft cooling tower, and associated valves, piping, and instrumentation. Since the design of the CWS may vary from site to site, the DCD in Tier 2 Section 10.4.5.2.1 states that the CWS and cooling tower are subject to site-specific modification or optimization. The combined license applicant will determine the final system configuration. DCD Tier 2 Table 10.4.5-1 provides CWS design data based on a conceptual design.

The DCD states that the reference design has been evaluated to verify that postulated CWS failures have no adverse impact on any safety-related SSCs. A postulated CWS line break in the yard area or a failure of the cooling tower basin has no detrimental effect on safety-related SSCs. The cooling tower will be located sufficiently distant from the nuclear island structures so that its postulated collapse does not affect equipment, components, or systems required for safe shutdown of the plant. The site is graded to drain water away from the seismic Category I structures. The seismic Category I structures below grade are protected from flooding by waterproofing systems and water stops. The COL applicant is responsible for determining the system configuration and may modify the design to meet site-specific requirements.

The cooling tower, which serves as a heat sink for the CWS, is site specific with its description in the DCD as a reference design using a hyperbolic natural draft structure. The cooling tower cools circulating water by discharging the water over a network of baffles in the tower and falls through fill material to the basin beneath the tower, so that heat is rejected to the atmosphere. The cooling tower basin serves as a storage facility for the circulating water inventory and allows bypassing of the cooling tower during cold weather operations. The bypass is used only during plant startup in cold weather, or to maintain the CWS temperature above 4.4 °C (40 °F) while operating at partial load during periods of cold weather. Makeup water is supplied to the cooling tower basin by the raw water system for the water losses in the CWS. Blowdown from the CWS is discharged to the waste water system. Makeup to and blowdown from the CWS is controlled by the makeup and blowdown control valves.

In DCD Tier 2 Table 10.4.5-1, Westinghouse specifies that the circulating water temperature from the cooling tower to the condenser is 32.2 °C (90 °F) when the wet bulb temperature is at 26.7 °C (80 °F) during limiting site conditions. Because the water temperature in the cooling tower varies with weather conditions, the circulating water temperature to the condenser will change accordingly. Higher circulating water temperature results in increased pressure in the condenser due to a decreased rate of steam condensation. Specific site conditions that exceed the wet bulb temperature of 26.7 °C (80 °F) will be accommodated by specific site analysis to adjust cooling system capability.

Three CW pumps take suction from the CW intake structure and circulate the water through the TCS, the condenser vacuum seal water heat exchangers, and the tube side of the main condenser and discharge to the cooling tower. The underground portion of the CWS piping is concrete pressure pipe; the rest is carbon steel pipe that is coated with a corrosion preventive compound inside the pipe. DCD Tier 2 Section 10.4.5.2.2 states that the CWS piping, expansion joints, butterfly valves, condenser water boxes, and tube bundles are designed for a maximum pump discharge pressure of 414 ka (60 psig).

The effects of flooding due to a CWS failure, such as a rupture of an expansion joint, will not result in detrimental effects on safety-related equipment because there is no safety-related equipment in the turbine building. A small CWS leak in the turbine building will drain into the waste water system. A large CWS leak due to pipe failure will be indicated in the control room by a gradual loss of vacuum in the condenser shell. The base slab of the turbine building is located at grade elevation and water from a system rupture will run out of the building through a relief panel in the turbine building reference plant west wall before the water level could rise high enough to cause damage.

Circulating water chemistry is maintained by the turbine island chemical feed system and controlled by cooling tower blowdown and chemical addition. The chemicals can be divided into six categories based on function, i.e., biocide, algicide, pH adjustor, corrosion inhibitor, scale inhibitor, and a silt dispersant. The use of these specific chemicals is determined by the site water conditions. The COL applicant will determine the use of the specific chemicals in the CWS chemistry control. (See Section 10.5 of this report for COL Action Items.)

In DCD Tier 2 Section 10.4.5.2.3, Westinghouse states that when the condenser is not available due a to malfunction of the CW pumps, cooling tower, or the CW piping, cooldown of the reactor may be accomplished by using the power-operated atmospheric steam relief valves or safety valves rather than the turbine bypass system. The staff concurs with this alternate cooldown method because the turbine bypass system will not function during accident conditions and the CWS is not required for safe shutdown following an accident.

On the basis of its review, the staff concludes that the design of the circulation water system meets the requirements of GDC 4, with respect to the effects of discharging water that may result from a failure of a component or piping in the CWS. Acceptance is based on the following design provisions:

- The CWS is designed to prevent flooding of safety-related areas so that the intended safety function of a system or component will not be precluded due to leakage from the CWS.

- The CWS is designed to detect and control flooding of safety-related areas so that the intended safety function of a system or component will not be precluded due to leakage from the CWS.

- Malfunction of a component or piping of the CWS, including an expansion joint, will not have unacceptable adverse effects on the functional performance capabilities of safety-related system or components.

Therefore, the staff concludes that the design of the CWS meets the guidelines of SRP 10.4.5.

10.4.6 Condensate Polishing System

The staff reviewed DCD Tier 2 Section 10.4.6, “Condensate Polishing System,” in accordance with Section 10.4.6, “Condensate Cleanup System,” of the SRP. The condensate polishing system (CPS) is acceptable if it prevents adverse chemistry conditions that could degrade the primary coolant boundary integrity. The CPS does not perform any safety-related function.

The CPS is used to remove corrosion products and ionic impurities from the condensate system during plant startup, hot standby, power operation with abnormal secondary cycle chemistry, safe shutdown, and cold shutdown operations.

The major components of the CPS are the following:

- Deep Bed Mixed Resin Polisher,
- Resin Trap,
- Spent Resin Trap, and the
- Resin Addition Hopper and Eductor.

One-third of the condensate is directed to one of two polishing vessels which are piped in parallel. A second polisher is on stand-by or in the process of being cleaned, emptied, or refilled. The two polishing vessels contain mixed-bed, ion-exchange resin with a strainer installed downstream of each vessel. The strainers are used to prevent the release of resin beads into the feed system.

The staff evaluated the design and operational requirements of the CPS and concluded that it meets the intended function of maintaining secondary coolant quality by including the necessary components to remove dissolved and suspended impurities which may be present in the condensate during normal operation and anticipated operational occurrences.

The staff's review has determined that while the CPS does not serve any safety-related function, its design is acceptable in meeting the intended function of maintaining secondary coolant quality by including the necessary components to remove dissolved and suspended impurities which may be present in the condensate.

10.4.7 Condensate and Feedwater System

The staff reviewed the condensate and feedwater system (CFS) in accordance with Section 10.4.7, "Condensate and Feedwater System," of the SRP. Conformance with the acceptance criteria of the SRP forms the basis for concluding that the CFS satisfies the following:

- GDC 2, with respect to withstanding the effects of natural phenomena (such as earthquakes, tornados, and floods).

- GDC 4, with respect to withstanding the effects of possible fluid flow instabilities (such as water hammers).

- GDC 44, “Cooling water,” with respect to the capability to transfer heat loads from the reactor system to a heat sink under both normal operating and accident conditions.

- GDC 45, “Inspection of cooling water system,” with respect to permitting periodic ISI of systems, components, and equipment.

- GDC 46, “Testing of cooling water system,” with respect to design provisions to permit functional testing of the system and components for structural integrity and leak-tightness.

The CFS that provides a continuous feedwater supply to the steam generators is composed of piping and components from the condensate system, main feedwater system, and portions of the steam generator system. The condensate system collects condensed steam from the condenser and pumps the condensate to a deaerator. The deaerator removes dissolved gases from the condensate to provide a source of high-quality heated feedwater supply. A main feedwater line takes suction from the deaerator and supplies heated feedwater to each of the two steam generators during all modes of plant operation.

The CFS contains three 50-percent-capacity motor-driven condensate pumps and three motor-driven feedwater pumps. Two condensate pumps are required during power operation. The spare condensate pump will start automatically on loss of one of the normally running condensate pumps and/or low condensate header discharge pressure. The three main feedwater pumps take suction from the associated feedwater booster pumps which draw water from the deaerator storage tank. Westinghouse states in the DCD that the feedwater pump, condensate pump, and the pump control systems are designed so that loss of one booster/main feedwater assembly or one condensate pump does not result in a trip of the turbine generator or reactor.

The safety-related isolation function of the CFS is accomplished by redundant means. A single active component failure of the safety-related portion of the system does not compromise the safety function of the system. DCD Tier 2 Table 10.4.7-1 provides the failure analysis results for those occurrences that result in reduced heat transfer in the steam generators. Loss of all feedwater is also evaluated in DCD Tier 2 Section 15.3.

Each main feedwater line to the steam generator contains a feedwater flow element, a main feedwater isolation valve (MFIV), a main feedwater control valve (MFCV), and a check valve. The MFIVs, installed in each of the two feedwater lines outside the containment, are used to prevent uncontrolled blowdown from the steam generators in the event of a feedwater line break. The MFCVs (located in the auxiliary building) are used to control feedwater flow rate to the steam generator during normal operation and provide a backup isolation to limit high-energy fluid addition through the broken loop in the event of a main steamline break. The feedwater check valves (located outside the containment) provide backup isolation to prevent reverse flow from the steam generators whenever the feedwater pumps are tripped. The check valves prevent blowdown from more than one steam generator in the event of feedwater line break while the ESF signal is generated to isolate the MFIV and MFCV.

On the basis of the above discussion, the staff finds that the CFS is capable of supplying sufficient feedwater water to the steam generators as required during normal operation and has incorporated appropriate redundancy for containment and feedwater isolation.

The feedwater system does have a connection with the startup feedwater system but does not have the safety function to transfer heat under accident conditions and, therefore, GDC 44 is not applicable.

During normal plant operation, as well as during plant upset or accident conditions, possible fluid flow instabilities in the feedwater piping when flow is entering the steam generator may cause water hammer in the system piping. Generic Safety Issue (GSI) A-1 was raised after the occurrence of various incidents of water hammer in operating plants that involved steam generator feedrings and feedwater piping. The staff reviewed the dynamic effects associated with possible water hammers in the feedwater piping for compliance with the requirements of GDC 4. Acceptance is on the basis of meeting the guidance contained in the branch technical position (BTP) ASB 10-2, "Design Guidelines for Avoiding Water Hammer in Steam

Generators," with respect to feedwater control induced water hammer. Specifically, BTP ASB 10-2 recommends the CFS to be designed with the following provisions:

- prevent or delay water draining from the feedring following a drop in steam generator water level.

- minimize the volume of feedwater piping external to the steam generator which could pocket steam using the shortest horizontal run of inlet piping to the feedring.

- perform tests, acceptable to the NRC, to verify that unacceptable feedwater hammer will not occur and provide test procedures for staff approval.

- implement pipe refill flow limits where practical.

Westinghouse states in the DCD that the potential for water hammer in the feedwater line would be minimized by the improved design and operation of the feedwater delivery system with the following features:

- The main feedwater pipe connection on each of the steam generators is the highest point of each feedwater line downstream of the MFIV, and the feedwater lines contain no high point pockets that could trap steam.

- The feedwater enters the steam generator at an elevation above the top of the tube bundle through a feedwater nozzle and below the normal water level by a top discharge feedring.

- The feedwater enters a feedring via a welded thermal sleeve connection and leaves it through nozzles attached to the top of the feedring.

- The feedwater line connected to the steam generator is a short, horizontal or downward sloping feedwater pipe at the steam generator inlet which will help keep the feedring full of water.

- Operational limitations on flow to recover steam generator levels and on early feedwater flow into the steam generator to maintain the feedring full of water will minimize the potential for water hammer occurrence.

DCD Tier 2 Section 5.4.2.2 states that these features will prevent the formation of steam pockets during steam generator low level conditions and minimize the potential for trapping pockets of steam that could lead to water hammer events. The top discharge of the feedring, through the nozzles, will help to reduce the potential for vapor formation in the feedring and the heated feedwater will reduce the potential for water hammer in the feedwater piping or steam generator feedrings.

The staff reviewed the DCD using the guidance of BTP ASB 10-2 and finds that the cited design features would minimize, but not necessarily eliminate, water hammer occurrence in the AP1000 feedwater system design. DCD Tier 2 Section 14.2 describes the initial test program which includes flow testing to detect possible feedwater hammer in the feedwater piping.

The staff concludes that the CFS design meets the requirements of GDC 4 with respect to testing for water hammer occurrence. The evaluation of the CFS to conform to GDC 4 with respect to protection from the effects of missile and high-energy line breaks is provided in Sections 3.5 and 3.6 of this report.

The staff reviewed the CFS for compliance in the requirements of GDC 2. Compliance with the requirements of GDC 2 is based on adherence to the guidance of RG 1.29, "Seismic Design Classification," Position C.1 for the safety-related portion, and Position C.2 for non-safety-related portion. The DCD indicates that the CFS is non-safety-related and serves no safety function except the portion of the feedwater piping routed into containment that requires containment and feedwater isolation. The portion of the feedwater system from steam generator inlets outward through the containment up to and including the MFIVs is safety-related and has the following safety-related functions:

- automatically isolate the main feedwater flow to the steam generators when it is required to mitigate the consequences of a steamline or feedwater line break.

- provide a barrier against the release of containment atmosphere during a loss-of-coolant-accident (LOCA).

- serve as a boundary for ensuring that steam generator levels can be maintained when the main feedwater pumps are not available.

The safety-related portion of the CFS is required to remain functional after a design-basis accident to provide containment and feedwater isolation. This portion will be designed and tested in accordance with the requirements of Section III of the ASME Code for Class 2 components which requires the CFS to be seismic Category I and protected from wind, tornado, missile, and dynamic effects. The non-safety-related portion of the CFS, from the MFIV inlets to the piping restraints at the interface between the auxiliary building and the turbine building, is designed in accordance with the requirements of Section III of the ASME Code for Class 3 components and is seismic Category I. Therefore, the CFS design is consistent with the guidance of RG 1.29, Position C.1 for safety-related portions and Position C.2 for nonsafety-related portions of the system. Based on this review, the staff concludes that the CFS design satisfies the guidance in the SRP for meeting the requirements of GDC 2, as it relates to protection of the system against natural phenomena.

The AP1000 design can be used at either single-unit or multiple-unit sites. Criterion 5 of DCD Tier 2 Section 3.1.1 states that the AP1000 design is a single-unit plant and 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 COL applicant must apply for the evaluation of the units' compliance with the requirements of GDC 5 with respect to the capability of shared systems and components important to safety to perform their required safety functions. A COL applicant must comply with GDC 5 for a multiple-unit site; therefore, the staff finds that the requirements of GDC 5 are satisfied as it relates to whether shared SSCs important to safety are capable of performing required safety functions.

The DCD states that both the safety-related and non-safety-related portions of the feedwater system are designed and configured to accommodate ISI in accordance with ASME Code, Section XI. Therefore, GDC 45 is satisfied with respect to permitting periodic ISI of system components and equipment. The DCD also states that the feedwater system is designed so that the active components are capable of limited testing during plant operation. Therefore, GDC 46 is satisfied with respect to design provisions to permit appropriate functional testing of the system and components to assure structural integrity and leak-tightness. The evaluation of the CFS with respect to periodic ISI of the system's components and equipment is addressed in Section 6.6 of this report.

On the basis of its review, the staff concludes that the design of the CFS meets the NRC regulations set forth in GDC 2, 4, 44, 45, and 46 and is acceptable. The following provide the basis for this conclusion:

- Westinghouse meets the requirements of GDC 2 with respect to the system being capable of withstanding the effects of earthquakes by meeting RG 1.29, Position C.1, for the safety-related portion, and Position C.2 for the non-safety-related portion.

- Westinghouse meets the requirements of GDC 4 with respect to the dynamic effects associated with possible fluid flow instabilities by having the feedwater system designed and tested in accordance with the guidance contained in BTP ASB 10-2, and thereby eliminating or reducing the possibility of water hammers in the feedwater system.

- Westinghouse does not have to meet the requirements of GDC 44 because the AP1000 design does not have a safety-related auxiliary feedwater system to provide flow to the steam generator via the feedwater system during accident conditions for decay heat removal.

- Westinghouse meets the requirements of GDC 45 and GDC 46 because the safety-related portions of the system are located in accessible areas for inspection and the active components are capable of limited testing during power operation in accordance with the TSs.

10.4.8 Steam Generator Blowdown System

The staff reviewed DCD Tier 2 Section 10.4.8, "Steam Generator Blowdown System," in accordance with Section 10.4, "Steam Generator Blowdown System," of the SRP. The steam generator blowdown system (SGBS) is acceptable if it satisfies requirements of:

- GDC 1, "Quality standards and records," as it relates to system components being designed, fabricated, erected and tested for quality standards,

- GDC 2, "Design bases for protection against natural phenomena," as it relates to system components designed to withstand the effects of natural phenomena such as earthquakes, i.e., designed to seismic Category 1 requirements, and

- GDC 14, "Reactor coolant pressure boundary," as it relates to secondary water chemistry control so that the primary coolant boundary material integrity will be maintained.

GDC 1 is met through RG 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containment Components of Nuclear Power Plants," and

RG 1.143, “Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants,” Position C.1.1.

The safety related portion of the SGBS related to high-energy pipe break location and evaluation is discussed in DCD Tier 2 Section 3.7, “Seismic Design.” The corresponding section in this report evaluates this portion of the SGBS against GDC 2 ensuring that it is classified as seismic Category I and designed to withstand a safe shutdown earthquake as delineated in RG 1.29, “Seismic Design Classification,” and RG 1.143, “Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants.”

The primary function of the SGBS is to remove steam generator secondary-side impurities and thus assist in maintaining acceptable secondary-side water chemistry in the steam generators. The portion of the SGBS related to secondary water chemistry control is discussed in DCD Tier 2 Section 9.3.4, “Secondary Sampling System.” The corresponding section in this report evaluates this portion of the SGBS against GDC 14 ensuring that secondary water chemistry is maintained to avoid corrosion-induced failure of the RCPB and that the probability of leakage from or rapidly propagating failure of the RCPB does not increase during the life of the plant.

The SGBS consists of two blowdown trains, one for each SG. A crosstie is provided to process blowdown from both SGs through both heat exchangers during high capacity blowdown from one SG. The blowdown water is extracted from each SG from a location just above the tubesheet. The blowdown from each SG is cooled by a regenerative heat exchanger, and flow is controlled and pressure reduced by a blowdown flow control valve. To recover the thermal energy, the condensate system provides cooling for the heat exchangers. To recover the blowdown fluid, each blowdown train has an electrodeionization EDI demineralizing unit which removes impurities from the blowdown flow. Downstream, two trains combine into a common header that contains a relief valve for overpressure protection for the low-pressure portion of the system. A backpressure control valve maintains pressure in the system between the flow control valve and the back-pressure control valve. A pump is provided to drain the secondary side of the SG and for recirculation during low-pressure SG wet layup and cooling operations. System isolation under normal operating and transient conditions is accomplished by two isolation valves which close on actuation of the passive residual heat removal system, containment isolation, or high blowdown system radiation, temperature, or pressure.

During normal operation, the blowdown flowrate varies from a minimum of 0.06 percent to a maximum of about 0.6 percent of the maximum steaming rate. During this time, when impurities are low, the expected blowdown rate is approximately 0.1 percent of the maximum steaming rate (about 114 L/min (30 gpm total), or 57 L/min (15 gpm) per SG), which maximizes the detection sensitivity for condenser tube leakage. In the event of main condenser tube leakage, when the concentration of impurities is high, the blowdown rate is increased to a maximum of approximately 0.6 percent of the maximum steaming rate (about 170 gpm total, or 85 gpm per SG). Normal operation is to recover the blowdown flow through the condensate system. However, blowdown with high levels of impurities can be discharged to the waste water system.

The staff also reviewed the SGBS as it relates to water chemistry control; i.e., its ability to remove particulate and dissolved impurities from the SG secondary side. The components within this system and the continuous high-flow blowdown are designed to control the concentration of impurities. In addition, the staff's evaluation of the secondary sampling system (SSS) is discussed further in Section 9.3.4, “Secondary Sampling System,” of this report.

Based on the discussion provided by the applicant and the staff evaluation in Section 9.3.4, “Secondary Sampling System,” the staff determined that the design of the SGBS ensures that secondary water chemistry will be controlled to avoid corrosion-induced failure of the reactor coolant pressure boundary (RCPB) and that there is sufficient blowdown flow needed to maintain secondary coolant chemistry for normal operation and anticipated operational occurrences.

Since the SGBS is considered an extension of the primary containment, this system is classified as seismic Category I and Quality Group B from its connection to the SG inside the primary containment, up to and including the first isolation valve outside the containment, in accordance with RGs 1.26 and 1.29. In addition, the SGBS downstream of the outer containment isolation valves, up to and including the piping anchors located at the auxiliary building wall, are designed in accordance with the requirements of Class 3 of Section III of the ASME Code and seismic Category I requirements. Piping downstream of the auxiliary wall anchors is not safety-related and not seismic Category I; nevertheless, the piping and components of this system meet the quality standards of Position C.1.1 of RG 1.143 in that these components are designed and tested to the requirements set forth in the codes and standards listed; the materials are compatible with the chemical, physical, and radioactive environment during normal conditions and anticipated operational occurrences; and the foundations and walls housing these components are designed to the natural phenomena and internal and external man-induced hazards criteria. The staff concluded that by meeting the regulatory positions in Rgs 1.26, 1.29, and 1.143, the AP1000 design satisfies GDC-1 and GDC-2 with respect to maintaining the system pressure boundary. Further, the staff's review determined that the design of the SGBS includes the appropriate components in addition to an adequate blowdown flow-rate to control the concentration of impurities during normal operation and anticipated operational occurrences, and thereby satisfies GDC 14.

10.4.9 Startup Feedwater System

The AP1000 plant does not have a safety-related auxiliary feedwater system. Instead, a non-safety-related startup feedwater system (SFS) is used to supply feedwater to the steam generators during plant conditions of startup, hot standby, cooldown, and unavailability of main feedwater pumps. The SFS is not required to supply feedwater under accident conditions, but the system is expected to be available as a non-safety-related first line of defense to provide a source of feedwater for loss of feedwater events. The safety-related passive core cooling system (PXS) will provide safety-grade protection for such events. Therefore, the operation of the SFS will not be credited to mitigate a design-basis accident described in DCD Tier 2 Chapter 15.

Because the passive design philosophy departs from current licensing practice, the staff may not require the non-safety-related active SFS to meet all the safety-related criteria specified in Section 10.4.9, "Auxiliary Feedwater System," of the SRP. However, the availability of the system must be ensured when needed in its defense-in-depth roles. Consequently, regulatory oversight measures are considered for those significant non-safety active systems. As with the AP600, the staff's review considered whether the design of the startup feedwater system:

- has sufficient redundancy to ensure defense-in-depth functions.
- has electric supplies from both normal station ac and onsite non-safety-related ac power supplies that are separated to the extent practicable.
- is designed and arranged for conditions or an environment anticipated during and after events to ensure operability, maintenance accessibility, and plant recovery.
- is protected against internal flooding and other in-plant hazards, including the effects of pipe ruptures, jet impingement, fires, and missiles.
- can withstand the effects of natural phenomena (such as earthquakes, tornados, and floods) without the loss of capability to perform required function.
- has a QA program applied to it.
- is included in the design reliability assurance program (DRAP) and under the scope of the Maintenance Rule (10 CFR 50.65) to ensure proper and effective maintenance, surveillance, and ISI and testing.
- has graded safety classifications and graded requirements for instrument and control (I&C) systems based on the importance to safety of their function to meet the reliability/ availability (R/a) missions.
- has proper administrative controls for shutdown configurations.
- is consistent with guidance in RG 1.29, BTP ASB 10-1, and BTP (SRXB) 5-1 concerning seismic classification, power diversity, and design of residual heat removal systems.

- is consistent with guidance in NUREG-0737 and NUREG-0611 concerning generic improvements to the startup feedwater system design, TSs, and SFS reliability.

The SFS has two trains, which share common suction and discharge piping. Two parallel startup feedwater pumps are provided with a single pump capable of satisfying the SFS flow demand for decay heat removal. Each of the two trains contains a 100-percent capacity motor-driven startup feedwater pump.

During normal startup and shutdown operations, the two startup feedwater pumps take suction from the condensate storage tank to supply feedwater to the two steam generators. In the event of loss of offsite power that results in a loss of main feedwater supply, the SFS automatically supplies feedwater to the steam generators to cool down the reactor under emergency shutdown conditions. The startup feedwater pumps automatically start following the loss of main feedwater flow in conjunction with an intermediate low steam generator level setpoint. The startup feedwater flow transmitters also provide redundant indication of startup feedwater and automatic safeguards actuation input on low flow coincident with a low, narrow-range steam generator level.

Each of the two startup feedwater pumps and its associated instruments and electric valves are powered by the standby source motor control center circuit. The pump discharge isolation valves are motor operated and are normally closed and interlocked with the startup feedwater pumps. In the event of loss of offsite power, the startup feedwater pumps will be powered by the onsite standby power supply (diesels). If both the normal ac power and the onsite standby ac power are unavailable, these valves will fail as is. The pump suction header isolation valves are pneumatically actuated. The SFS also has temperature instrumentation in the pump discharge that would permit monitoring of the SFS temperature.

On the basis of the above discussion, the staff finds that the startup feedwater pumps possess diversity in motive power source with an electric supply from both normal station ac and onsite non-safety-related ac power supplies that are separated. Therefore, the staff concludes that the design of the startup feedwater pumps meets the redundancy and power source review criteria.

Preoperational testing of the SFS is described in DCD Tier 2 Chapter 14. Each startup feedwater pump is equipped with a recirculation line to the demineralized water storage tank for periodic functional testing. When one pump is being tested, the other pump will remain available for automatic operation. Currently, periodic surveillance tests of the auxiliary feedwater pumps and their associated flow trains for the operation plants are required by the standard TSs. TS 3.7.7 in DCD Tier 2 Section 16.1 was provided for the startup feedwater isolation valves and control valves as they are safety-related. The inservice testing program for the SFS is described in DCD Tier 2 subsection 3.9.6.

Item II.E.1.1 of NUREG-0737, "Clarification of TMI Action Plan Requirements" (dated November 1980), recommends that all operating PWR plants perform auxiliary feedwater system reliability analysis. Generic Safety Issue 124 addresses the use of probabilistic risk assessment (PRA) to evaluate the reliability of the auxiliary feedwater system. SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs" (dated April 2, 1993), provides the interim position on the reliability assurance program applicable to AP1000 design certification. Accordingly, Westinghouse performed reliability analysis for the main and startup feedwater systems that was addressed in Appendix C8 of the AP1000 PRA.

Westinghouse also performed a startup feedwater system component failure analysis, with the results identified in DCD Tier 2 Table 10.4.9-1, which listed several cases where startup feedwater flow is not available to the steam generator. The analysis indicates that failure of startup feedwater supply has no effect on RCS function.

The SFS has no safety-related function other than containment and startup feedwater isolation. The portion of the SFS piping that penetrates the containment from the startup feedwater isolation valve (SFIV) to the connection at the steam generator is safety-related, and is required to function following a design-basis accident to perform safety functions such as containment isolation, steam generator isolation, and feedwater isolation. This portion is designed in accordance with the requirements of Section III of the ASME Code for Class 2 components and is seismic Category I. The portion of the SFS piping from the SFIV inlets to the pipe restraints at the interface between the auxiliary building and turbine building is non-safety-related and is designed in accordance with Section III of the ASME Code for Class 3 components and is seismic Category I. As specified in DCD Tier 2 Table 3.2-3, other valves and remaining piping of the SFS meet ANSI B31.1 requirements and are classified as Class D.

The startup feedwater line connects directly to the steam generator nozzle rather than via the main feedwater piping. The design makes the main feedwater system and the startup feedwater system parallel systems. The main feedwater system draws water from the deaerator tank and delivers it to the main feedrings within the steam generator, but the startup feedwater system draws water from the condensate storage tank and delivers it to the startup feedwater nozzle on the steam generator. The design allows main feedwater pumps to deliver water to the startup feed headers but does not allow the startup feed pumps to deliver water to the main feed headers.

Westinghouse stated that the startup feedwater piping layout includes the same features as the main feedwater piping layout, such as a downward elbow in close proximity to the startup feedwater nozzle on the steam generator, exclusion of high points for limiting void collection, redundant positive isolation to prevent back leakage, and delivery of startup feedwater to steam generator independent of feedrings. The startup feedwater system is sized, operated, and has water sources consistent with minimizing the potential for water hammer. The staff finds that Westinghouse considered water hammer prevention in the SFS design change.

Double-valve startup feedwater isolation is provided by the SFIV and the startup feedwater control valve (SFCV) located outside the containment. The SFIV and SFCV are powered from separate Class 1E power sources to provide redundant and independent actuation. DCD Tier 2 Section 10.4.9.1.1 states that the SFCVs and SFIVs are designed to close on an appropriate engineered safety signal (startup feedwater isolation signal).

On the basis of its review, the staff concludes that the SFS design meets the review criteria for non-safety systems serving defense-in-depth functions.

10.4.10 Auxiliary Steam System

The current SRP does not include a section specifically addressing the auxiliary steam system. The staff determined that the acceptability of the system will be on the basis of meeting the requirements of GDC 4, in that failure of the auxiliary steam system as a result of a pipe break or malfunction of the system should not adversely affect safety-related systems or components.

The auxiliary steam system supplies steam required by the unit for a cold start of the main steam system and turbine generator. It also provides steam during plant operation for hot water heating. Main steam supplies the auxiliary steam header during normal operation. The auxiliary boiler provides steam to the header during a plant shutdown. The auxiliary steam boiler has a rated capacity of 110,000 pounds per hour of saturated steam at 195 psig. The system is protected from overpressure by safety valves on the boiler, boiler deaerator, and auxiliary steam header.

The auxiliary steam system is a non-safety-related system classified as AP1000 Class E. The system consists of an auxiliary steam system and boiler, pumps, auxiliary boiler deaerator, chemical treatment components, and auxiliary boiler fuel oil components.

Operational safety features are provided within the system for the protection of plant personnel and equipment. The auxiliary steam system does not interface directly with nuclear process systems. The auxiliary boiler is located in the turbine building, and none of the lines pass through areas where safety-related equipment is located. Therefore, the auxiliary steam system meets the requirements of GDC 4 in that failure of the system as a result of a pipe break or malfunction of the system should not adversely affect safety-related systems or components.

Testing of the auxiliary steam system is performed before initial plant operation. Components of the system are monitored during operation to verify satisfactory performance. Testing procedures for the auxiliary steam system are located in the system specification and vendors' equipment instruction manuals, which are not part of the AP1000 design certification review.

On the basis of the above review, the staff finds that the auxiliary steam system meets the requirements of GDC 4 in that failure of the auxiliary steam system as a result of a pipe break or malfunction of the system does not adversely affect safety-related systems or components, and therefore, the staff finds the auxiliary steam system acceptable.

10.5 Combined License Information Items

The Combined License holder will address preparation of an erosion-corrosion monitoring program for carbon steel portions of the steam and power conversion systems that contain water or wet steam. This monitoring program will address industry guidelines and the requirements included in Generic Letter 89-08. This is COL Action Item 10.5.1.

The Combined License holder will submit to the staff for review and approval within 3 years of obtaining a Combined License, and then implement a turbine maintenance and inspection program. The program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in DCD Subsection 10.2.3.6. The Combined License holder will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis. This is COL Action Item 10.5.2.

The Combined License applicant will address the final configuration of the plant circulating water system including piping design pressure, the cooling tower or other site-specific heat sink. As applicable, the Combined License applicant will address the acceptable Langelier or Stability Index range, the specific chemical selected for use in the CWS water chemistry control, pH adjuster, corrosion inhibitor, scale inhibitor, dispersant, algicide and biocide applications reflecting potential variations in site water chemistry and in micro macro biological lifeforms. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in DCD Section 6.4. This is COL Action Item 10.5.3.

The Combined License applicant will address the oxygen scavenging agent and pH adjuster selection for the turbine island chemical feed system. This is COL Action Item 10.5.4.

The Combined License applicant will address the specific biocide. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in Section 6.4. This is COL Action Item 10.5.5.