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 AP1000 Design Control Document (DCD) Tier 2, Chapter 10, "Steam and Power Conversion," describes the steam and power conversion system for the AP1000 design. 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. A closed-loop circulating water system (CWS) removes the heat rejected in the main condenser. 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 next discharged to the suction of the main feedwater pumps, which then discharge the feedwater through feedwater heaters to the two steam generators.

Steam from each of the 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
- erosion-corrosion protection

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

DCD Tier 2, Section 10.1, and Table 10.1-1 provide a description of the steam and power conversion system, as well as its design features and performance characteristics.

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 its integrated design meets the requirements of Part 50 of Title 10 of the Code of Federal Regulations (10 CFR Part 50). Specifically, the design must meet the requirements of Appendix A to 10 CFR Part 50, General Design Criteria for Nuclear Power Plants (GDC) 4, “Environmental and Dynamic Effects Design Bases,” as they relate to the protection of the structures, systems, and components (SSCs) that are important to safety from the effects of turbine missiles. GDC 4 provides for a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generation of turbine missiles. SRP Section 10.2.11 describes the specific criteria necessary to meet the requirements of GDC 4.

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

DCD Tier 2, Table 10.2-1 identifies the design parameters of the turbine generator. DCD Tier 2, Figure 10.3.2-2 provides the piping and instrumentation diagram (P&ID) containing the stop, governing control, intercept, and reheat valves. 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 turbine generator foundation is designed as 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 the 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) 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 the turbine speed exceed 103 percent of the rated speed. The loss of fluid pressure in the header causes the control and intercept valves to close. Following these valve closures, if the turbine speed falls below the rated speed and the header pressure is reestablished, the control and intercept valves are reopened and the unit resumes speed control. Section 10.2.2 of this report provides additional discussion of the DEH control system. In addition, an emergency trip system is provided to trip the turbine in the event that speeds exceed the overspeed protection control trip setpoint of 110 percent of the rated speed. Section 10.2.4 of this report provides additional discussion of the ETS.

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 mode is the speed control that functions to maintain the desired speed; 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). Section 10.2.3 of this report discusses the ATC. Valve opening actuation in the DEH control system is provided by a hydraulic system; closing actuation is provided by springs and steam forces upon reduction or relief of fluid pressure. A trip signal is sent to fast acting solenoid valves. Energizing these solenoid valves releases the hydraulic fluid pressure in the valve actuators, allowing springs to close each valve. The system is designed so that a 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

The ATC 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
- generating load holds

10.2.4 Turbine Protective Trips

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

- low bearing oil pressure
- low electrohydraulic fluid pressure
- high condenser back pressure
- turbine overspeed
- thrust bearing wear
- 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 an emergency trip control block, trip solenoid valves, a 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. In addition, turbine trip circuitry is tested prior to unit startup.

The NRC 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 to ensure turbine overspeed protection. The staff determined that the AP1000 turbine generator design conforms to 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, provides a 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, as well as to protect the reactor system from abnormal surges. To assure that turbine overspeed is controlled within acceptable limits, 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. The valve arrangements and valve closure times should ensure 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 stop valves 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, as well as 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 valves during startup and normal operations, and closes the valves rapidly upon loss of turbine loads. The reheat stop valves close completely upon 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 conforms to 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. No safety-related systems or components are 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 SSCs. Failure of the turbine generator equipment does not preclude a safe shutdown of the reactor. Section 3.5.1.3 of this report addresses the issue of turbine missiles.

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 should be provided under all operating conditions. Radiation shielding should be provided as necessary to permit access.

Under operating conditions, access is available to the 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 conforms to 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 the turbine building does not house any safety-related equipment.

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 excessive vibration of the turbine rotor assembly. The staff reviewed the measures taken by the applicant 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 the applicant to maintain 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. In addition, these criteria will ensure that the rotor is adequately designed and will be inspected prior to service, as well as receiving inservice inspections (ISIs) at approximately 10-year intervals during plant shutdowns.

The applicant provided its evaluation on turbine disk integrity which addressed all technical areas specified in SRP 10.2.3, including materials selection, fracture toughness, preservice inspection (PSI), turbine disk design, and ISI. For this evaluation, the applicant relied on the turbine missile methodology and analytical results documented in Westinghouse Commercial Atomic Power (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. Section 3.5.1.3 of this report includes a description of the analyses and the staff’s evaluation and acceptance of WCAP-15783 and WCAP-15785. Since high-pressure turbines have disks of smaller radius and lighter blades (less stresses) and are operated at a higher temperature (higher fracture toughness), the LP turbine results on missile generation bound the HP turbine results. SRP 10.2.3 addresses LP turbines only, and WCAP-15783 provides information on LP turbines accordingly.

DCD Tier 2, Section 10.2.3 provides information concerning the turbine rotor material. AP1000 turbine rotors are made from a vacuum-melted, deoxidized alloy steel (Ni-Cr-Mo-V) 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 that meet 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 its performance in service has been found acceptable. 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 necessary to assure an appropriate level of fracture toughness.

The applicant 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 Charpy V-notch (C_V) properties obtainable from water-quenched Ni-Cr-Mo-V material of the size and strength level used, thus indicating that suitable material toughness is obtained through the use of these types of material. The applicant’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 applicant’s response to RAI 251.024 dated March 25, 2003, clarified their fracture toughness requirements. This response indicated 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 2. 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 pressure-temperature limits for the reactor pressure vessel. However, this criterion for fracture toughness of the rotor material was not consistent with the second design criterion of DCD Tier 2, Section 10.2.3.4, which states that “[t]he 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.” This was draft safety evaluation report (DSER) Open Item 10.2.8-1.

In a letter dated July 7, 2003, the applicant provided a response to this open item by revising DCD Tier 2, Section 10.2.3.4. This revision explicitly connects the applied stress intensity factor for an ultrasonic testing (UT) reportable flaw to fracture toughness of the rotor material. Since the applicant has removed the conflict between the criteria, Open Item 10.2.8-1 is resolved.

In DCD Tier 2, Section 10.2.3.2, “Fracture Toughness,” the applicant discusses, in general terms, the maximum initial flaw size and crack growth rates. Section 3.5.1.3 of this report discusses the staff’s evaluation of the application of nondestructive examination (NDE), initial flaw size, and crack growth rates with respect to the probability aspects of turbine missile generation. 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 to resolve certain concerns about the applicant’s analysis.

DCD Tier 2, Section 10.2.3.2.1 describes a brittle fracture analysis in terms of 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, the applicant 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 presented in DCD Tier 2, Section 3.5.1.3, as well as its review of the turbine rotor integrity presented in DCD Tier 2, Section 10.2.3.) WCAP-15783 describes completely the brittle fracture analysis discussed in DCD Tier 2, Section 10.2.3.2.1. The staff considers this response appropriate because the limiting dimension (radius) of a rotor shaft is much larger than the limiting dimension (disk thickness) of turbine disks, which makes the operational stresses in the shaft much lower than the operational stresses in the disks, and makes the disks more limiting than the shaft. Hence, the WCAP-15783 analyses for disks are sufficient for assessing overall rotor integrity.

In Revision 2 of WCAP-15783, the applicant replaced an unreasonable stress intensity factor (K_{IC}) value used in the LCF analysis, as identified in RAI 251.025, with a proprietary value the staff considers reasonable for the design material. In its response to RAI 251.026, dated March 25, 2003, regarding the vibratory stresses, the applicant 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 location different from where the LCF effect is evaluated. However, the response did not adequately justify the conclusion that rotor resonant stresses resulting from passing through rotor critical speeds are insignificant. This was DSER Open Item 10.2.8-2.

In response to DSER Open Item 10.2.8-2 dated June 24, 2003, the applicant provided quantitative information regarding rotor resonant stresses resulting from passing through rotor critical speeds. This new information indicates that (1) the reported rotor resonant stresses are about one quarter of those associated with high cycle fatigue (HCF), as discussed in WCAP-15783, and (2) the duration of the rotor resonant stresses is short as opposed to the cyclic nature of HCF, making the contribution of the rotor stresses to HCF or LCF negligible at its critical speeds. Therefore, DSER Open Item 10.2.8-2 is resolved.

In its response to RAI 251.027 regarding the K_{IC} value, its associated safety factor, and the assumed initial flaw depth that was used in the fatigue crack growth analysis, the applicant stated that the requested information can be found in WCAP-15783. Further, the applicant 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, RAI 251.002 addresses the determination of an initial flaw depth. The closure of DSER Open Item 3.5.1.3-1 in Section 3.5.1.3 of this report further addresses this issue.

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, to verify the fracture toughness of 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 plant-specific rotor test data provided by the combined license (COL) applicant to support this assumed value, the applicant states that the assumed fracture toughness for LCF evaluations is based on the design curves for fracture toughness of 3.5 percent Ni-Cr-Mo-V steel. The fracture toughness curves provided reflect Mitsubishi Heavy Industry's (MHI) test data and experience and include a 20 percent margin. The applicant further states "[t]he minimum allowable fracture toughness for the AP1000 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 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 a 20 percent margin. However, as required by DCD Tier 2, Section 10.2.6, 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. (See Section 10.5 of this report, COL Action Item 10.5-2.)

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, low-pressure, 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 due to the reduction of surfaces susceptible to SCC and the elimination of interference fits which induce higher stresses. The nonbored design of the high-pressure rotors provides increased design margins because of inherently lower centerline stress. The use of solid rotor forgings was qualified by an evaluation of the material removed from center-bored rotors used in fossil power plants. This evaluation demonstrated that the material at the center of the rotors meets the requirements of the materials specification. Further, DCD Tier 2, Section 10.2.3.4 states that only suppliers that have been qualified based on bore materials performance will supply forgings for high-pressure rotors. Therefore, both the nonbored design of the high-pressure turbine element and the bored design of the low-pressure 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. The DCD also states that the tangential stresses will not cause a flaw that is twice the corrected UT 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 was DSER Open Item 10.2.8-3. In its letter of

July 7, 2003, the applicant responded to this open item by revising the first design criterion of DCD Tier 2, Section 10.2.3.4, to be consistent with the stress limit criterion of SRP 10.2.3. Hence, DSER Open Item 10.2.8-3 is resolved.

DCD Tier 2, Section 10.2.3.5, “Preservice Tests and Inspections,” states that the 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 its rated speed. The proposed preservice tests and inspections, as well as the acceptance criteria for the examination results are more restrictive than those specified for Class 1 components in Section III and V of the ASME Code. Therefore, the staff finds them acceptable.

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 inspections 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 will be dismantled and inspected by visual and surface examinations approximately every 3 years during scheduled refueling or maintenance shutdowns. Turbine valve testing will be 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, the applicant 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 clarified that the turbine inspection intervals are supported by WCAP-15783 and WCAP-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. Section 3.5.1.3 of this report discusses the NRC staff’s review and acceptance of WCAP-15783, which is related to the resolution of Open Items 3.5.1.3-1 and 3.5.1.3-2.

WCAP-15785 complements WCAP-15783 by using detailed nuclear turbine failure data to assess the total risk of turbine missile ejection at destructive overspeed and at lower overspeeds as a function of valve test interval. WCAP-15785 contains detailed information regarding the method for calculating the probability of destructive overspeed using historical failure data pertinent to the operating experiences of MHI nuclear steam turbines. This WCAP report also outlines the use of this failure data to calculate failure rates for various components. 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 industry practice that has resulted in satisfactory performance. In addition, 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 tests 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, 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. (See Section 10.5 of this report, COL Action Item 10.5-2.)

10.2.9 Conclusions

Based on the above evaluation, the staff concludes that the AP1000 design is acceptable and meets the requirements of GDC 4 with respect to the protection of SSCs important to safety from the effects of turbine missiles. The applicant has met these requirements by providing a turbine overspeed protection system to control the turbine action under all operating conditions. This system also assures that a full-load turbine trip will not cause the turbine to overspeed beyond acceptable limits, thus resulting in turbine missiles.

With the 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 to 10 CFR Part 50. This conclusion is based upon the ability of the applicant to demonstrate 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 PSIs and ISIs. The applicant has also described its program for assuring the integrity of low-pressure turbine rotors, which includes the use of suitable materials of adequate fracture toughness, conservative design practices, PSI and ISI, and valve testing. This provides reasonable assurance that the probability of failure due to 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 Design

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 with respect to the ability of the safety-related portions of the system to withstand 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,” with respect to the ability of the 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

The NRC staff review also considers the following guidance:

- SRP Branch Technical Position (BTP) RSB 5-1 with respect to the design requirements for residual heat removal

- Issue 1 in NUREG-0138, “Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976, Memorandum From Director, NRR, to NRR Staff,” which specifies the allowable credit that can be 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, and main turbine system. 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 safety-related mechanical equipment in the MSSS and list 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 the main steam isolation valve and the main steam isolation bypass valves

- the inlet piping from the main steamline to the main steam safety valve discharge piping and vent stacks and to the 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, as well as 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 quality assurance (QA) requirements of Appendix B to 10 CFR Part 50 and is designed to the requirements discussed in DCD Tier 2, Sections 3.11 and 9.5 for environmental design and fire protection, respectively. The DCD also states that no single failure coincident with loss of offsite power compromises the safety functions of the MSSS.

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 (PRHR) system (see Section 5.4.14 of this report), which can be initiated automatically without requiring the control of steamline pressure, provides the capability of safety-grade decay heat removal. 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 requirements. Therefore, the staff concludes that the AP1000 design meets the position in BTP RSB 5-1 as it relates to the design requirements for residual heat removal.

Following a main steamline break, the main steam isolation system is designed to limit blowdown to one steam generator so that the fuel design limits and containment design pressure can be maintained. The MSIVs and the 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 to 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 the 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, 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. High-pressure hydraulic fluid maintains the values in an open position. For emergency closure, redundant Class 1E solenoid valves 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 stated 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 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. The MSIV technical specification (TS) includes control for the turbine stop valves, moisture separator/reheater stop valves, and turbine bypass valves. Based on the conclusions in NUREG-0138, the staff finds that the AP1000 MSSS meets the requirements of GDC 34, as they relate to limiting blowdown of a second steam generator in the event of a steamline break upstream of the MSIV. Further, based on meeting the relevant acceptance criteria specified in the SRP, the staff concludes that the MSSS meets the requirements of GDC 34, as they relate 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 to ensure that the safety-related portions of the system are capable of withstanding the effects of natural phenomena such as earthquakes, tornados, hurricanes, and floods. The design should also meet, the positions of Regulatory Guide (RG) 1.29, “Seismic Design Classification,” as they relate to the seismic design classification of system components, and RG 1.117, “Tornado Design Classification,” as they relate to the protection of SSCs important to safety from the effects of tornado missiles.

The 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. The 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 are also designed to these requirements. 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 designated 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. Section 3.4.1 of this report describes the staff's evaluation of flood protection. The safety-related mechanical equipment in the MSSS is identified in DCD Tier 2, Table 3.2-3, and described in DCD Tier 2, Section 10.3.1.1. Based on its review, the staff concludes that the safety-related portion of the system meets the requirements of GDC 2 of Appendix A to 10 CFR Part 50 with respect to the ability of the structures housing the safety-related portion of the system and the safety-related portions of the system to withstand the effects of natural phenomena.

Compliance with GDC 4 is based on meeting the relevant requirements specified in the SRP to ensure 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 RG 1.115, "Protection Against Low-Trajectory Turbine Missiles," as it relates 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, as well as operating and maintenance procedures that emphasize proper draining. The applicant 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.

DCD Tier 2, Sections 3.6.1 and 3.6.2 discuss high-energy pipe break locations and evaluate the effects of such breaks, including pipe whip and jet impingement forces. 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 meet the leak-before-break (LBB) criteria. DCD Tier 2, Section 3.6.3 discusses the LBB application and criteria. Section 3.6.1 through 3.6.3 of this report provides the staff's evaluation of this issue. Leakage detection for the purpose of LBB is discussed in Section 3.6.3 of this report.

Section 3.5 of this report includes an evaluation of the protection provided by the AP1000 design against externally- and internally-generated missiles. Sections 3.5 and 3.6 of this report evaluates the conformance of the design in this area with the requirements of GDC 4.

Although the AP1000 design can be used at either single-unit or multiple-unit sites, DCD Tier 2, Section 3.1.1 states that the AP1000 design is a single-unit plant. Further, 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 to the requirements of 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": Appendix A to 10 CFR Part 50, GDC 1, "Quality Standards and Records," and GDC 35, "Emergency Core Cooling System"; and Appendix B to 10 CFR Part 50, "Quality Assurance Criteria."

GDC 1 requires, in part, that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. 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 that 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 form which they are fabricated.

Appendix B to 10 CFR Part 50 establishes 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:

- The fracture toughness properties of the ferritic materials of Class 2 and 3 components are acceptable if they meet the requirements of NC-2300, "Fracture Toughness for Materials (Class 2)" and ND-2300, "Fracture Toughness for Materials (Class 3)" of Section III of the ASME Code.

- 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.

- The materials specified for use in Class 2 and 3 components are acceptable if welds located in areas of restricted direct and visual accessibility are welded by personnel qualified consistent with the guidance 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 that 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 Section III of the ASME Code, 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 standards of ASME, the American Society for Testing and Materials (ASTM), the American National Standards Institute (ANSI), or the 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. DCD Tier 2, Table 10.3.2-3 list the material specifications for the main steam and feedwater systems. DCD Tier 2, Section 1.9.1 describes conformance with the applicable RGs. DCD Tier 2, Section 6.6.5 addresses nondestructive inspection of ASME Code, Section III, Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems.

The staff's evaluation of the materials used in the main steam and feedwater systems is divided into the following three sections:

(1) 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 Section III of the ASME Code, 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.

(2) Material Selection and Fabrication: Carbon steel piping in steam and feedwater systems has experienced wall thinning due to 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. The applicant stated that it considered system piping and component configuration and geometry, water chemistry, piping and component material, fluid temperature, and fluid velocity in its evaluation of erosion-corrosion. 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. The COL applicant will perform pipe wall thickness inspections 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 applicant will prepare an erosion-corrosion monitoring program for the 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 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning.” This is COL Action Item 10.3.2-1.

DCD Tier 2, Section 10.3.6.2 indicates that 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 either 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 that 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 stated that the AP1000 design provides an alternative to RG 1.71. Section 5.2.3 of this report includes the staff’s evaluation of this alternative. DCD Tier 2, Section 1.9.1 indicates that the AP1000 design will comply with RG 1.37 with respect to the prevention of IGSCC in components fabricated from austenitic stainless steel and nickel-based alloys. Since the AP1000 design conforms with these RGs, the applicable requirements of GDC 1 and Appendix B to 10 CFR Part 50 are satisfied.

(3) Nondestructive Inspection: DCD Tier 2, Section 10.3.6.2 indicates that DCD Tier 2, Section 6.6.5 addresses the nondestructive inspection of ASME Code, Section III,

> Class 2 and 3 components in the safety-related portions of the main steam and feedwater systems. DCD Tier 2, Section 6.6, indicates that the rules for fabrication examinations found in Section III of the ASME Code will be followed. Section 6.6 of this report evaluates this section of the DCD. Therefore, the fabrication of the materials specified for use in Class 2 and 3 components will comply with the acceptance criteria of Section III of the ASME Code, 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. Therefore, they are 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; Appendix A to 10 CFR Part 50, GDC 1 and 35; and Appendix B to 10 CFR Part 50.

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 upon meeting the requirements of GDC 60, “Control of Releases of Radioactive Materials to the Environment,” as they relate to the design of the system to ensure 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.

DCD Tier 2, Section 10.4.1 describes the main condenser system of the AP1000 design; DCD Tier 2, Figure 10.4.7-1 depicts this design. DCD Tier 2, Table 10.4.1-1, “Main Condenser Design Data,” lists the 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, etc.).

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. It also 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 the plant’s full-load steam flow without either reaching the condenser overpressure 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 the spring-loaded safety valves.

The main condenser is a non-safety-related and nonseismic 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 safety-related equipment is not located in the turbine building. In addition, water cannot reach the safety-related equipment located in Category I plant structures. Therefore, the staff finds that the requirements of GDC 60 are met with respect to preventing flooding of areas housing safety-related equipment due to system failures.

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. Section 11.5 of this report discusses the radiological monitoring capabilities of the AP1000 design.

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 Performance 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 to 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
- 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. Each tube sheet is also provided with a grab sampling capability. This information helps to identify the leaking tube bundle. The steps that may be taken to repair a leaking tube bundle include

(1) isolate the circulating water system from the affected water box while at reduced plant power, (2) drain the water box, and (3) repair or plug the affected tubes.

The condensate polishing system (CPS) removes corrosion products and ionic impurities from the condensate system. This allows for continued operation with a “continuous” condenser tube leakage of 0.004 liters per minute (L/min) (0.001 gallons per minute (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. DCD Tier 2, Table 10.3.5-1 provides secondary cycle chemistry guidelines. DCD Tier 2, Section 10.3.5.5 discusses action levels for abnormal secondary cycle chemistry. Therefore, the staff finds that the requirements of GDC 60 are met with respect to condenser failures that do not result in 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 prevention of excessive releases of radioactivity to the environment resulting from failures in the system design. The AP1000 design 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

The condenser air removal system (CMS) is responsible for the evacuation of the main condenser. 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 GDC 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, “Quality Assurance Program Requirements (Operation),” and RG 1.123, “Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants,” in the acceptance criteria. In addition, the requirements of GDC 60 and 64 may be met by using the guidance contained in the following RGs and industrial standards:

- RG 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 and 1.123 as they relate to the QA programs for the CMS components that may contain radioactive materials

- The Heat Exchanger Institute's "Standards for Steam Surface Condensers," 6th Edition, as they relate 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 standards and, consistent with the guidance in RG 1.26, the CMS is in Quality Group D as listed in DCD Tier 2, 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 noncondensable gases and air from the two condenser shells of the main condenser during plant startup, cooldown, and normal operation and exhausts them into the atmosphere.

The applicant indicated in WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," that the CMS will conform with eighth edition of the Heat Exchanger Institute's "Standards for Steam Surface Condensers." In DCD Tier 2, Section 10.4.2.4, the applicant 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 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. The applicant 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 to QA for operation is similar to the approach taken for QA in the radwaste systems (see Sections 11.2 and 11.3 of this report) because radioactive contaminants can be introduced to the CMS through primary-to-secondary system leakage resulting from steam generator tube leakage. The staff agrees with the applicant that RG 1.123 has been withdrawn and is therefore 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.

The MSSS and steam generator BDS radiation devices provide early detection of concentrated levels of radioactivity. In addition to this monitoring, the TDS provides radioactive effluent monitoring equipment at the combined exhaust of the CMS and the 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. 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 64 are met with respect to the control and monitoring of radioactivity releases to the environment. Section 11.5 of this report discusses the radiological monitoring capabilities of the AP1000 design.

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

10.4.3 Turbine Gland Seal System

The staff reviewed the design of the 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 GDC 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 RGs 1.33 and 1.123 in the acceptance criteria. In addition, the requirements of GDC 60 and 64 may be met by using the guidance contained in the following RGs:

- RG 1.26, 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 and 1.123, 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 noncondensable 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/noncondensable 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, is in the Quality Group D, as listed in DCD Tier 2, 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 the main steam system. The GSS is tested in accordance with written procedures during the initial testing and operation program. The turbine vendor provides testing procedures for the system in its equipment instruction manuals. During normal operation, the monitoring of essential parameters will demonstrate the satisfactory operation of the system components. Pressure and temperature indicators 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. The TDS provides a radiation detector with an alarm.

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. The applicant 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 to QA for operation is similar to the approach taken for QA in the radwaste systems (see Sections 11.2 and 11.3 of this report) because radioactive contaminants can be introduced to the GSS through primary-to-secondary system leakage resulting from steam generator tube leakage. The staff agrees with the applicant that RG 1.123 has been withdrawn and is therefore not applicable to the AP1000 GSS.

The mixture of noncondensable gases discharged from the gland steam condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage resulting from 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. Section 11.5 of this report discusses the radiological monitoring capabilities of the AP1000 design. Because the above systems continuously monitor and detect the radioactivity, and because operating procedures may be implemented to control unacceptable levels of radiation, GDC 60 and 64 are met with respect to the control and monitoring of 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 to GDC 60 and 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 following GDC 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 in a controlled manner from the steam generators bypassing the turbine to the main condenser to dissipate heat and to minimize transient effects on the reactor coolant system (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 located 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 electropneumatically 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 a 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. DCD Tier 2, Section 10.4.4.3 discusses the system operation. 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 a 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, the 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 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, the applicant 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. Turbine rupture discs provide ultimate overpressure protection for the condenser. If the bypass valves fail closed, the power-operated relief valves permit a controlled cooldown of the reactor. DCD Tier 2, Chapter 15 addresses the effects of 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 nonseismic category building. No safety-related equipment is located within the turbine building or near the turbine bypass system. Therefore, the staff concludes that the turbine bypass system complies with the requirements of GDC 4 regarding the adverse effects of a pipe break or malfunction on those components of the system necessary for shutdown or accident prevention or mitigation because such components do not exist 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, P&IDs, and descriptive information for the turbine bypass system and the auxiliary supporting systems that are essential to its operation.

The basis for accepting the design, design criteria, and design bases of the turbine bypass system is their conformance to GDC 4 and 34 of Appendix A to 10 CFR Part 50 as explained below:

- The AP1000 design meets the requirements of GDC 4 with respect to the system's ability to allow a safety shutdown despite a failure of the turbine bypass system.

- The AP1000 design meets the requirements of GDC 34 with respect to the ability to use the turbine bypass system to shut 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 34.

10.4.5 Circulating Water System

The NRC staff reviewed the 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 they relate to provisions in the AP1000 design 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 requirements:

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

- means to prevent adverse 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 designed to provide a continuous cooling water supply to the main condenser, the heat exchangers of the turbine building closed cooling water system (TCS), and heat exchangers for the condenser vacuum pump seal water 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, DCD Tier 2, Section 10.4.5.2.1 states that the CWS and cooling tower are subject to site-specific modification or optimization. The COL 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 in its description; the DCD provides 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. The water then 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 the cooling tower to be bypassed 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. The raw water system supplies makeup water to the cooling tower basin for the water losses in the CWS. The makeup and blowdown control valves regulate the makeup to and blowdown from the CWS.

In DCD Tier 2, Table 10.4.5-1, the applicant 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. Site-specific analysis will accommodate specific site conditions that exceed the wet bulb temperature of 26.7 °C (80 °F) and will be used 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 kPa (60 pounds per square inch gauge (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 the turbine building does not house safety-related equipment. 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. Water from a system rupture will run out of the building through a relief panel in the west wall of the turbine building reference plant 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 the cooling tower blowdown and chemical addition. The chemicals can be divided into six categories based on whether they are a biocide, algicide, pH adjustor, corrosion inhibitor, scale inhibitor, or a silt dispersant. Site water conditions will determine the use of these specific chemicals. 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, the applicant states that when the condenser is not available due to a 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 CWS 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 systems 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 include the following:

- deep bed mixed resin polisher
- resin trap
- spent resin trap
- 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 standby 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 criteria:

- 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 leaktightness

The CFS provides a continuous feedwater supply to the steam generators and 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 upon 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 lead to reduced heat transfer in the steam generators. DCD Tier 2, Section 15.3 evaluates the loss of all feedwater.

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 to 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 a 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 to the steam generators as required during normal operation. The AP1000 design also incorporates 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 that could occur 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 based on meeting the guidance contained in 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 that the CFS be designed to achieve 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

The applicant states in the DCD that the potential for water hammer in the feedwater line would be minimized by the improved design and operation of a 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 will 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. 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. Sections 3.5 and 3.6 of this report provides the staff's evaluation of the CFS to conform to GDC 4 with respect the effects of missile and high-energy line breaks on the system.

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

- automatically isolates the main feedwater flow to the steam generators when it is required to mitigate the consequences of a steamline or feedwater line break
- provides a barrier against the release of containment atmosphere during a loss-of-coolant accident
- serves 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 of the system will be designed and tested in accordance with the requirements of Section III of the ASME Code for Class 2 components. This requires the CFS to be seismic Category I and to be 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. This portion 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 non-safety-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 they relate to protecting 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. 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 they relate 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 Section XI of the ASME Code. 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. Section 6.6 of this report provides the NRC staff's evaluation of the CFS with respect to periodic ISI of the system's components and equipment.

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, therefore, acceptable. The following provides the basis for this conclusion:

- The AP1000 meets the requirements of GDC 2 with respect to the system's ability to withstand the effects of earthquakes by meeting RG 1.29, Position C.1, for the safety-related portion of the system, and RG 1.29, Position C.2 for the non-safety-related portion of the system.

- The AP1000 meets the requirements of GDC 4 with respect to the dynamic effects associated with possible fluid flow instabilities by designing and testing the feedwater system in accordance with the guidance contained in BTP ASB 10-2, thereby eliminating or reducing the possibility of water hammers in the feedwater system.

- The AP1000 does not have to meet the requirements of GDC 44 because the 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.

- The AP1000 meets the requirements of GDC 45 and GDC 46 because the safety-related portions of the system are accessible for inspection and the active components are capable of limited testing during power operation in accordance with the plant's TS.

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 the following requirements:

- GDC 1, as it relates to the quality standards for system component design, fabrication, erection and testing

- GDC 2, as it relates to the design of system components to withstand the effects of natural phenomena such as earthquakes (i.e., seismic Category I requirements)

- GDC 14, "Reactor Coolant Pressure Boundary," as it relates to the use of secondary water chemistry control to maintain the integrity of the primary coolant boundary material

GDC 1 is met through RGs 1.26 and 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants."

DCD Tier 2, Section 3.7, "Seismic Design," discusses the safety-related portion of the SGBS associated with high-energy pipe break location and evaluation. 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 RGs 1.29 and 1.143.

The primary function of the SGBS is to remove secondary-side impurities of the steam generator, thus assisting in maintenance of acceptable secondary-side water chemistry in the steam generators. DCD Tier 2, Section 9.3.4, "Secondary Sampling System," discusses the portion of the SGBS related to secondary water chemistry control. Section 9.3.4 of 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 reactor coolant pressure boundary (RCPB) and that the probability of leakage from a 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 backpressure 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 643 L/min (170 gpm) total or 322 L/min (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 secondary side of the SG). The components within this system and the continuous high-flow blowdown are designed to control the concentration of impurities. In addition, Section 9.3.4 of this report discusses the NRC staff's evaluation of the secondary sampling system (SSS) further.

Based on the discussion provided by the applicant and the staff evaluation in Section 9.3.4 of this report, the staff determined that the design of the SGBS ensures that secondary water chemistry will be controlled to avoid corrosion-induced failure of the RCPB. In addition, the staff determined that sufficient blowdown flow exists to maintain secondary coolant chemistry during 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 because (1) the components are designed and tested to the requirements set forth in the codes and standards listed, (2) the materials are compatible with the chemical, physical, and radioactive environment during normal conditions and anticipated operational occurrences, and (3) the foundations and walls housing these components are designed to the criteria for natural phenomena and internal and external man-induced hazards. The NRC staff concludes that by meeting the regulatory positions in RGs 1.26, 1.29, and 1.143, the AP1000 design satisfies GDC 1 and 2 with respect to maintaining the system pressure boundary. Further, the staff 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. This 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 startup, hot standby, cooldown, and the 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 in 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, as described in DCD Tier 2, Chapter 15.

Because the passive design philosophy departs from current licensing practice, the NRC 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 for its defense-in-depth roles. Consequently, regulatory oversight measures are considered for those significant non-safety active systems. 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 alternating current (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 (e.g., earthquakes, tornados, and floods) without the loss of capability to perform required functions

- has an associated QA program

- is included in the design reliability assurance program (DRAP) and is under the scope of the Maintenance Rule (10 CFR 50.65) to ensure proper and effective maintenance, surveillance, and inservice inspection and testing

- has graded safety classifications and graded requirements for instrument and control systems based on the importance to safety of their function and their ability to meet reliability availability 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, "Clarification of TMI Action Plan Requirement," and NUREG-0611 concerning generic improvements to the startup feedwater system design, TS, and SFS reliability

The SFS has two trains that 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 a 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 their 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.

DCD Tier 2, Chapter 14 describes preoperational testing of the SFS. 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, the standard TS require periodic surveillance tests of the auxiliary feedwater pumps and their associated flow trains for the operation plants. TS 3.7.7 in DCD Tier 2, Section 16.1 was provided for the startup feedwater isolation valves and control valves because they are safety-related. DCD Tier 2, Section 3.9.6 describes the inservice testing program for the SFS.

Item II.E.1.1 of NUREG-0737 recommends that all operating pressurized-water reactors perform auxiliary feedwater system reliability analysis. GSI 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,” provides the interim position on the reliability assurance program applicable to AP1000 design certification. Accordingly, the applicant performed reliability analysis for the main and startup feedwater systems that was addressed in Appendix C8 of the AP1000 PRA.

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

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 perform safety functions, such as containment isolation, steam generator isolation, and feedwater isolation, following a design-basis accident. This portion of the piping 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. In this design, the main feedwater system and the startup feedwater system are 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.

The applicant 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 the 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 (i.e., the 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 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. The current SRP does not include a section specifically addressing the auxiliary steam system. The staff determined that the acceptability of this system will be based on meeting the requirements of GDC 4. In other words, 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. The main steam system 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 49,900 kg/hr (110,000 pounds per hour) of saturated steam at 1,344 kPa (195 psig). The system is protected from overpressure by safety valves on the boiler, boiler deaerator, and auxiliary steam header.

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 because 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 because 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. Therefore, the staff finds the auxiliary steam system acceptable.

10.5 Combined License Action Items

The COL applicant will prepare 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 GL 89-08. This is COL Action Item 10.5-1.

The COL applicant will submit to the staff for review and approval within 3 years of obtaining a combined license a turbine maintenance and inspection program. Once approved, the COL applicant will then implement this program. The turbine maintenance and inspection program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in DCD Tier 2, Section 10.2.3.6. The COL applicant 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 COL applicant will address the final configuration of the plant circulating water system, including piping design pressure and the cooling tower or other site-specific heat sink. As applicable, the COL applicant will address the acceptable Langelier or Stability Index range; the specific chemicals selected for use in the CWS water chemistry control; and applications of chemical pH adjuster, corrosion inhibitors, scale inhibitors, dispersants, algicides, and biocides to reflect potential variations in site-water chemistry and in micro/macro-biological life forms. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. DCD Tier 2, Section 6.4 addresses the impact of toxic gases on the main control room compatibility. This is COL Action Item 10.5-3.

The COL 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 COL 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.