Chapter 10

STEAM AND POWER CONVERSION SYSTEM

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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 10

STEAM AND POWER CONVERSION SYSTEM

This chapter provides information concerning the plant steam power conversion (heat utilization) system. The steam and power conversion system (SPCS) includes the turbine-generator, steam supply system, feedwater system, main condenser, and related subsystems. The auxiliary feedwater (AFW) system is discussed in Section 6.5.

Descriptive information is provided to allow understanding of the system, with emphasis on those aspects of design and operation that affect the reactor and its safety features, or contribute to the control of radioactivity. The radiological aspects of normal system operation are summarized in this chapter and are presented in detail in Chapter 11. Design and quality code classifications applied to the SPCS are discussed in Chapter 3.

10.1 SUMMARY DESCRIPTION

The SPCS is designed to convert the heat produced in the reactor to electrical energy. In each unit, reactor heat absorbed by the reactor coolant system (RCS) produces sufficient steam in four steam generators (SGs) to supply the turbine-generator.

The SPCS is designed to operate on a closed, condensing cycle, with full flow condensate demineralization, and six stages of regenerative feedwater heating. Turbine exhaust steam is condensed in a single shell, surface-type condenser and returned to the SGs through three stages of feedwater pumping. All three low-pressure turbine elements exhaust into a common condenser steam space. The arrangement of the equipment associated with the SPCS is shown in Figures 3.2-2 through 3.2-4 and 10.3-6.

The SPCS is designed to receive the heat absorbed by the RCS during normal power operation, as well as following an emergency shutdown of the turbine-generator from full load. Heat rejection under the latter condition is accomplished by steam bypass to the condenser and pressure relief to the atmosphere. Either the turbine bypass or the pressure relief system (without operation of safety valves) can dissipate the heat from the RCS following a turbine trip and a reactor trip. Trips, automatic control actions, and alarms are initiated by deviations of system variables from preset values. In every instance, automatic control functions are programmed so that appropriate corrective action is taken to protect the RCS (refer to Chapter 7).

The SPCS does not normally contain radioactivity. The vents and drains associated with the secondary cycle are arranged in a manner similar to those in a conventional fossil fuel generating station. However, the condenser air removal equipment will handle radioactive noncondensable gases during a SG primary-to-secondary tube leak. Means are provided to monitor (refer to Section 11.6) the discharge of radioactive material to the environment, to ensure that it is within the limits of 10 CFR Part 20 under normal operating conditions, or in the event of anticipated system malfunctions or accident conditions. Detection of these gases is described in Sections 10.4.2 and 11.4.

All SPCS equipment required for nuclear safety is classified as PG&E Design Class I, and the appropriate systems are sufficiently redundant to ensure maintenance of their safety functions. Specifically, the AFW system and portions of the main steam and main feedwater systems are required to perform various safety functions involving removal of decay heat and are classified as PG&E Design Class I. Safety functions relative to the AFW system are presented in Section 6.5.

Turbine heat balances at maximum calculated and full load conditions are shown, respectively, in Figures 10.1-1 and 10.1-2 for Unit 2, and Figures 10.1-5 and 10.1-6 for Unit 1. Typical operating parameters for the secondary system are listed in Table 10.1-2.

Tables 10.1-1 and 10.1-2 summarize important design and performance characteristics of equipment upon which the safety of the SPCS operation depends. The design performance characteristics and PG&E Design Class I design features are described in the remainder of Chapter 10.

10.1.1 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by Diablo Canyon Power Plant (DCPP) procedures.

10.2 TURBINE-GENERATOR

The basic function of the turbine-generator is to convert thermal energy initially to mechanical energy and finally to electrical energy. The turbine-generator receives saturated steam from the four SGs through the main steam system. Steam is exhausted from the turbine-generator to the main condenser.

10.2.1 DESIGN BASES

10.2.1.1 Turbine-Generator System Safety Function Requirements

(1) Protection from Missiles

The turbine-generator is designed to ensure that failure of the turbine-generator is minimized and will not result in the generation of missiles that could affect safe shutdown of either unit.

10.2.1.2 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The turbine-generator meets the requirement of 10 CFR 50.62 by responding to an anticipated transients without scram (ATWS) mitigation system actuation circuitry (AMSAC) signal to trip the turbine under ATWS conditions.

10.2.1.3 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls in accordance with Generic Letter 89-08, May 1989 to assure long-term implementation of its erosion/corrosion monitoring program for the turbine-generator.

10.2.2 SYSTEM DESCRIPTION

The Siemens-Westinghouse BB96 high pressure (HP) turbine is coupled to three Alstom ND56R low pressure (LP) turbines in a four-casing, tandem-compound, six-flow exhaust, 1800 rpm unit, with 57-inch last-stage blades. The ac generator is connected to the turbine shaft, and a brushless exciter is coupled to the generator.

10.2.2.1 Turbine

The turbine consists of one double-flow, high-pressure element in tandem with three double-flow, low-pressure elements. Moisture separation and reheating of the steam are provided between the high-pressure and LP turbines by six horizontal axis, two-stage reheat cylindrical shell combined moisture separator-reheater (MSR) assemblies. Three of these assemblies are located on each side of the low-pressure turbine elements.

Steam from the exhaust of the high-pressure turbine element enters one end of each MSR assembly, where internal manifolds in the lower section distribute the wet steam. The steam then flows through a moisture separator where the moisture is removed and the condensate drained to a drain tank from which it is pumped to the suction of the main feedwater pumps. The steam leaving the separator flows over two tube bundles where it is reheated in two stages. The reheated steam leaves through nozzles in the top of the assemblies and flows to the LP turbines through a stop valve and an intercept valve in each reheat steam line. Two MSR assemblies furnish steam to each of the three low-pressure turbine elements. The first stage tube bundle in the reheater is supplied with extraction steam from the high-pressure turbine, and the second-stage tube bundle is supplied from the main steam lines ahead of the high-pressure turbine. The supply steam condenses in the tubes; the condensate from the high-pressure tube bundle flows to the shell of the high-pressure feedwater heaters, while the condensate from the low-pressure tube bundle flows to the heater 2 drain tank.

A turbine shaft sealing system, using steam to seal the annular openings where the shaft penetrates the casings, prevents steam outleakage or air inleakage along the shaft. Turbine steam extraction connections are provided for six stages of feedwater heating.

10.2.2.2 Performance Requirements

The main turbine-generators and their auxiliary systems are designed for steam flow corresponding to 3,500 MWt and 3,580 MWt, which in turn correspond to the maximum calculated thermal performance data of the Unit 1 and Unit 2 nuclear steam supply systems (NSSSs), respectively, at the original design ultimate expected thermal power. The Unit 2 turbine-generator has a higher power rating because of subsequent uprating of the Unit 2 NSSSs. The intended mode of operation of both Unit 1 and Unit 2 is base loaded at levels limited to the lower licensed reactor level of 3,411 MWt (refer to Table 15.1-1).

10.2.2.3 Operating Characteristics

The SG characteristic pressure curves (refer to Figure 10.2-1) are the bases for design of the turbine. The SG pressure curve shown in Figure 10.2-1 corresponds to the SG outlet pressure. The calculated curve is based on thermal design conditions with vessel T_{avg} of 577.6ºF and 10 percent SG tube plugging (Reference 1). The pressure at the turbine main steam valves does not exceed the pressure shown on the steam characteristic pressure curve for the corresponding turbine load. With a pressurized water reactor, it is recognized that the pressure at the turbine steam valves rises as the load on the turbine is reduced below rated load. During abnormal conditions at any given load, the pressure may exceed the pressure on the SG characteristic pressure curve by 30 percent on a momentary basis, but the total aggregate duration of such momentary swings above characteristic pressure over the whole turbine load range does not exceed a total of 12 hours per 12-month operating period.

The turbine inlet pressure is not directly controlled. A load index from the turbine first-stage pressure is compared to the reactor coolant loop T_{avg}; the control rods are then positioned accordingly (refer to Section 7.7.2.8).

10.2.2.4 Functional Limitations

The plant is designed to sustain sudden large load decreases, as described in Section 5.1.7.2. This capability is provided by the use of controlled steam dump (turbine bypass) from the secondary system. This dump serves as a short-term artificial load, allowing the reactor to automatically cut back power without tripping. The reactor control system itself is not rapid enough to follow a sudden loss of load without allowing certain reactor plant variables (e.g., pressure and temperature) to exceed allowable operating limits. Therefore, a sufficiently large controlled steam dump, capable of simulating an external load on the reactor, is used to prevent the reactor from tripping.

The rates at which electrical load may be increased or decreased without tripping the reactor, including operation of the steam dump (bypass system), are as follows:

(1) Without steam bypass - If electrical load decrease does not exceed a step change of 10 percent, or a sustained ramp load decrease of 5 percent per minute, then the steam bypass will not operate. Steam bypass is not used to control load increases.

(2) With steam bypass - If electrical load decrease does exceed a step change of 10 percent or a sustained ramp load decrease of 5 percent per minute, then a combination of steam dump groups 1, 2, and 3 of the turbine bypass system(TBS) (refer to Section 10.4.4.2) will operate. If the decrease is less than 50 percent, then a step change with control rods will account for a 10 percent load decrease, and the TBS will operate and control up to 40 percent of the remaining load decrease.

(3) Electrical load increases are limited by the reactor control system to 5 percent full power per minute, or step changes of 10 percent of full power within the power range of 15 to 100 percent of full power.

For further explanation of the steam bypass and relief system, refer to Section 10.4.4. Steam bypass and relief valves are listed in Table 10.1-1. For electrical loading, refer to Chapter 8, Electric Power.

The functional limitations imposed by the design or operational characteristics of the turbine-generator are:

(1) Retrofitted with Alstom LP turbines, the units are suitable for continuous full load underfrequency operation down to 56.4 Hz. Operation below 56.4 Hz is limited to 10 seconds per event. There is no specific accumulated time limit for operation below 56.4 Hz. A trip within 0.5 seconds is required below 54.9 Hz.

(2) Under frequency set points and time delays are coordinated with PG&E's Under Frequency Load Shedding Program, per Utility Operations Standard UO S1426, which conservatively bounds turbine vendor requirements.

(3) Load changes cause thermal stress in the turbine rotor, which persists as long as there are differences between the surface and interior temperatures of the rotor body. Operational procedures for changing load, that tend to ensure a maximum time period before the appearance of fatigue cracking, are required. Load changing recommendations are based on 10,000 cycles of general turbine operation. For example, the following load changes can be made instantaneously, without exceeding the 10,000-cycle recommendations: 0-10 percent, 10-30 percent, 20-53 percent, 30-78 percent, 40-85 percent, and 50-100 percent.

(4) Operation at less than 5 percent rated load should be avoided; however, when necessary, auxiliary load may be carried indefinitely on the main generator following rejection of the main load, provided;

   (a) Low-pressure turbine exhaust hood spray is placed in service when hood temperature exceeds 175°F; and if hood temperature increases to 250°F for more than 15 minutes, the turbine is tripped

   (b) All supervisory instrument readings are within allowable alarm limits

10.2.2.5 Lubrication

Turbine-generator bearings are lubricated by a conventional oil system. The volute type, centrifugal main oil pump is mounted on the turbine rotor and supplies all of the oil requirements for the lubrication system during normal operation. An ac motor-driven centrifugal pump supplies bearing oil for operating the turbine-generator on turning gear during coastdown after a trip, and during startup. A backup dc motor-driven bearing oil pump operates, in case of loss of ac power or if the ac pump fails to start, to lubricate the turbine-generator bearings during coastdown of the unit after tripout. Air-side and hydrogen-side ac motor-driven seal oil pumps are provided to supply oil to the generator hydrogen seal oil systems. An air side dc motor-driven seal oil backup pump operates in case of loss of ac power, to prevent leakage of the generator hydrogen. A lift pump is provided for bearings 3, 4, 5, 6, and 7 to lift the turbine rotor shaft off the journal bearing to reduce the starting load on the turning gear motor. Bearing 8 was retrofitted with an integral bearing lift system.

10.2.2.6 Cooling

The cooling water requirements of the turbine-generator are met partially by the service cooling water system (refer to Section 9.2.1), and partially by the main condensate and feedwater system (refer to Section 10.4.7).

The following main turbine-generator heat exchangers are cooled by the service cooling water system:

(1) Turbine lubricating oil coolers

(2) Generator hydrogen seal oil coolers

(3) Exciter air-to-water heat exchangers

(4) Electrohydraulic (EH) control fluid cooler

(5) Main generator isophase bus duct cooler

The following main turbine-generator heat exchangers are cooled by the main condensate and feedwater system:

(1) Generator hydrogen coolers

(2) Generator stator water coolers

(3) Gland steam condenser

10.2.2.7 Turbine Electrohydraulic Control System

The turbine is equipped with a digital electrohydraulic (DEH) control system that uses programmable triple modular redundant digital controllers, dual redundant digital servo position controllers, input/output modules, and a high-pressure, fire-resistant, fluid supply system to operate the turbine control valves. By regulating the flow of steam through the turbine, the control system regulates turbine speed prior to the time that the generator is synchronized, and controls unit power output when the generator is connected to the PG&E transmission system. The control system also provides overspeed protection. Retrofitted with Alstom LP turbines, the control system also provides low condenser vacuum and low bearing oil protection.

Unit electrical loading is completely under the control of the reactor operator except when automatic runbacks are in progress. No automatic offsite load dispatching is utilized.

10.2.2.8 Turbine Steam Flow Control

The flow control of the main inlet steam is accomplished by four main stop valves in series with four governor control valves.

Each main stop valve operates in either a fully opened or fully closed position. The valve is opened when high-pressure fluid enters the hydraulic actuator cylinder and forces the piston to overcome spring closing pressure. It is closed immediately upon the dumping of main stop valve emergency trip fluid to provide quick closing independent of the electrical system. The valve may also be closed upon activation of the solenoid valve for periodic test of valve stem freedom. The purpose of the main stop valve, which is installed in the main steam line ahead of the governor control valve, is to provide an additional safety device to limit turbine overspeed. On a unit trip, stop and governing valves are spring-closed to provide redundancy for turbine overspeed protection.

Each governor control valve is of the single-seat, plug type design. The valve is opened when high pressure EH fluid enters the actuator and overcomes the spring force of the valve as transmitted by the operating levers. During normal operation, control of the governor control valve is by a servo valve that regulates oil pressure in the actuator, based on information supplied from the DEH system controller. A linear variable differential transformer (LVDT) develops an analog signal proportional to the valve position, which is fed back to the controller to complete the control loop. The controller signal positions the control valves over a wide range of turbine speeds during startup and for load control after the unit is synchronized. The governor control valve is closed by reducing pressure on the dump valve. The dump valve can be activated by means of the emergency trip system, or by the auxiliary governor trip, to provide quick closing independent of the electrical system.

The flow control of steam to the low-pressure sections of the turbine is accomplished by six reheat stop valves in series with six interceptor valves.

Each reheat stop valve operates in either the fully opened or fully closed position. The valve is opened when high-pressure fluid enters the actuator hydraulic cylinder and forces the piston to overcome spring closing pressure. It is closed immediately upon dumping of main stop valve emergency trip fluid, on actuation of the emergency trip device. It may also be closed upon activation of the solenoid valve for periodic testing of valve stem freedom. The major function of the reheat stop valves is to shut off the flow of steam to the low-pressure turbines, when required.

Each interceptor valve normally operates in a fully opened position. The valve is opened when high-pressure fluid is admitted through an orifice to the hydraulic cylinder operating piston. As the fluid pressure increases beneath the piston, it overcomes the force of the closing springs and opens the steam valve. It is quickly closed when the emergency trip fluid is released to drain. The purpose of this valve is to limit the flow of steam from the MSRs to the low-pressure turbines after a sudden load reduction.

10.2.2.9 Partial Loss of Load

A feature called close-intercept valve (CIV) was built into the original turbine control system to close the intercept valves. This CIV feature was designed to sense a load mismatch between HP exhaust pressure and generated power. CIV actuation would close the intercept valves for a preset time period. This feature was disabled on the original Westinghouse-supplied turbine control system and is not present in the new system.

10.2.2.10 Complete Loss of Load

When a mismatch of LP turbine inlet pressure and generator output megawatts occurs, and the breaker opens, this condition is detected as a complete load loss. When the generator breaker opens, the load drop anticipation (LDA) is set, requesting overspeed protection control (OPC) action. Refer to Section 10.2.3.1 for a description of the OPC system.

All governor and interceptor valves are then rapidly closed. The LDA load loss circuit is inoperable below 22 percent of load, as measured by LP turbine inlet pressure.

10.2.2.11 Overspeed Action

OPC action also occurs when turbine speed is equal to, or greater than, 103 percent of rated speed. Governor and interceptor valves are closed until the speed drops below 103 percent.

The OPC system may be tested by using the OPC test function. If the breaker is open and the OPC test function is activated, a signal is generated; this signal indicates that the speed of the turbine is over 103 percent. The OPC system then closes the valves as though an actual overspeed condition had occurred.

10.2.2.12 Speed Channel System

Three separate electromagnetic pickups input speed information to the turbine control system. These inputs are validated against a high and low reference to determine when a transducer fails high or low. The control system uses a median signal select logic to determine the controlling speed signal for turbine speed control, OPC, and redundant overspeed protection.

10.2.2.13 Automatic Runbacks and Programmed Ramps

The turbine control system implements protective runbacks and programmed ramps (load reductions). The OTΔT and OPΔT protective runbacks are described in Section 7.7.2.4.2. The loss of main generator stator cooling protective runback is discussed in Section 10.2.2.15. Main turbine programmed ramps anticipating loss of steam flow are main feedwater pump trip and heater drip pump trip. A turbine runback anticipating a loss of heat sink is a trip of a circulating water pump.

10.2.2.14 Trip System Operability

The operability of the main turbine inlet valves and turbine trip system is verified by periodic functional tests. Operability of the trip system in the event of postulated accidents has also been reviewed. The trip system is protected from falling debris and will remain operational during and following postulated accidents (refer to Section 3.5.2.2.2.1).

Administrative operating requirements ensure that the turbine building crane is parked away from the steam inlet valves during turbine operation, to preclude damage to the valves from a postulated crane fall.

10.2.2.15 Protective Features

Post Alstom LP turbine retrofit, the low vacuum mechanical trip feature has been removed and low vacuum trip is now provided through the DEH. The following other protective devices are independent of the electronic controller and, when initiated, will cause tripping of all turbine valves:

(1) Mechanical overspeed trip (refer to description in Section 10.2.3.1)

(2) Low bearing oil pressure trip (this is provided by both the mechanical trip, independent of the electronic controller, as well as through the DEH).

(3) Thrust bearing trip

(4) Electrical solenoid trip, actuated by:

  (a) Safety injection (SI) system or SG high-high level

(b) Generator loss of field

(c) Reactor trip

(d) Unit trip

(e) Manual trip switches in control room

(f) Turbine speed 111.5 percent or dc bus trip (DEH)

(g) AMSAC

(5) Manual lever located at the turbine

Each of the above tripping devices releases autostop oil. The oil release results in a decrease of autostop oil pressure that opens a diaphragm-operated trip valve in the EH high-pressure fluid system to release the pressure and close all steam valve actuators.

The generator is protected by a load runback feature on loss of cooling water to the generator stator. The runback is accomplished at a rate of approximately 40 percent load drop per minute by the turbine control system. If the generator runback fails to start in 45 seconds, the generator is additionally protected by a time delay trip, which results in a unit trip. Reverse power and antimotoring protection is also provided for the generator.
High-high SG water level signals in two-out-of-three channels for any SG actuate a turbine trip, trip the main feedwater pumps, and close the main feedwater control valves and feedwater bypass valves. The purpose is to protect the turbine and steam piping from excessive moisture carryover caused by high-high SG water level.

In addition to the devices described above, the turbine and steam system are protected by the following indicators and design features:

(1) Dropped reactor control rod signal light on the main control board

(2) Isolation valve in each SG steam line

(3) Check valve in each SG steam line

(4) Safety valves in each SG steam line

(5) Safety valves in the MSR inlet (cold reheat) piping

(6) Extraction line nonreturn valves

(7) Exhaust casing rupture diaphragms

(8) Turbine steam and casing drains which open automatically at loads less than 20 percent

The turbine-generator and associated steam handling equipment have received extensive mechanical, electrical, and radiological safety evaluations. Protective features regarding personnel and equipment safety are presented in this section. Safety features for reactor protection, in the event of a turbine-generator trip or sudden load reduction, are presented in Section 10.4.4.

10.2.2.16 Design Codes

The turbine-generator and associated components are classified as PG&E Design Class II. Section 3.2 presents a discussion of design classifications and code requirements.

10.2.3 SAFETY EVALUATION

10.2.3.1 Turbine-Generator System Safety Function Requirements

(1) Protection from Missiles

Tests and analyses regarding the potential generation and effects of missiles, caused by the turbine-generator are discussed in Section 3.5.2.2.1. Criteria for determining the turbine inspection scope and frequency required to prevent missile generation are also discussed in Section 3.5.2.2.1.

The OPC system controls turbine overspeed in the event of a partial or complete loss of load, or if the turbine reaches or exceeds 103 percent of rated speed. In the event that turbine shaft speed exceeds 103 percent of rated speed, overspeed protection is afforded through information (in rpm) supplied by three speed transducers to the OPC system. The signals from the transducers are validated against a high and low reference to determine when a transducer fails high or low. The turbine control system uses a median signal select logic to determine the controlling speed signal.

A mechanical overspeed trip device is also provided that will automatically trip the unit at 111 percent of rated speed. The mechanism consists of a spring-loaded plunger located in the turbine shaft, which extends radially outward when 111 percent of rated speed is reached. When extended, the plunger contacts a lever, which in turn dumps control hydraulic fluid (autostop oil), causing all turbine steam inlet control and stop valves to close.

An electronic trip signal is generated by the DEH control system, at 111.5 percent of rated speed, as redundant overspeed protection. With the retrofitted Alstom LP turbines, this trip signal is used to energize two solenoid valves, either of which dumps autostop oil. This trip signal is set approximately 10 rpm higher than the mechanical overspeed device previously described.

Overspeed protection is necessary to preclude turbine rotor failure and associated turbine generated missiles (refer to Section 3.5.2.2.1).

10.2.3.2 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The turbine-generator meets the requirement of 10 CFR 50.62 by responding to an AMSAC signal to trip the turbine under ATWS conditions. The main turbine must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS (refer to Section 7.6.3.6).

10.2.3.3 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls in accordance with Generic Letter 89-08, May 1989 to assure long-term implementation of its erosion/corrosion monitoring program for the turbine-generator.

10.2.4 TESTS AND INSPECTIONS

Turbine-generator tests and inspections are described in Sections 3.5.2.2.2.1, 10.2.2.11, 10.2.2.14, and 10.2.3.1.

10.2.5 INSTRUMENTATION APPLICATIONS

Instrumentation is provided to continuously monitor and alarm the following turbine-generator parameters:

(1) Shaft vibration at main bearings

(2) Shaft eccentricity

(3) Shell expansion

(4) Differential expansion between turbine shell and rotor

(5) Turbine speed

(6) Turbine metal temperatures

(7) Bearing temperatures

(8) Hydrogen gas and stator cooling water temperatures

(9) Exhaust hood temperatures

(10) Condenser vacuum

(11) Thrust bearing wear

10.2.6 REFERENCES

1. Delta 54 Replacement Steam Generator Thermal and Hydraulic Design Analysis Report for Diablo Canyon, WCAP-16573-P, August 2007.

10.3 MAIN STEAM SYSTEM

The main steam system conveys the generated steam from the NSSS to the turbine generator, turbine driven feedwater pumps, steam dump, reheaters, and via the auxiliary steam system, to the gland steam system and air ejectors. Main steam is also provided to the turbine driven AFW pump.

Refer to Section 10.4.4 for details on the 10 percent atmospheric dump valves.

The main steam system structures, systems and components (SSCs) from the SGs up to and including the main steam isolation valves (MSIVs) outside of the containment are PG&E Design Class I. The main steam system SSCs downstream of the MSIVs are PG&E Design Class II.

10.3.1 DESIGN BASES

10.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the main steam system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, winds, floods and tsunamis, and other local site effects. The effects of a tornado on the main steam system are addressed to ensure plant safe shutdown can be achieved.

10.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portion of the main steam system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.3.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The PG&E Design Class I portion of the main steam system and its components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

10.3.1.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the main steam system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.3.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the main steam system variables within prescribed operating ranges.

10.3.1.6 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The PG&E Design Class I portion of the main steam system is provided with instrumentation for sensing accident conditions and initiating the operation of necessary engineered safety features.

10.3.1.7 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The main steam system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions. The effluent discharge path includes both the PG&E Design Class I and PG&E Design Class II portions of the system.

10.3.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main steam system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

10.3.1.9 General Design Criterion 40, 1967 – Missile Protection

The engineered safety feature (ESF) containment isolation portion of the main steam system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.3.1.10 General Design Criterion 49, 1967 – Containment Design Basis

The main steam system is designed so that the containment structure can accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident (LOCA), including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

10.3.1.11 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The PG&E Design Class I portion of the main steam system that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.3.1.12 General Design Criterion 57, 1971 – Closed System Isolation Valves

The PG&E Design Class I portion of the main steam system is designed such that each line that penetrates containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere has at least one containment isolation valve which is either automatic or locked closed or capable of remote-manual operation. This valve is outside containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve.

10.3.1.13 Main Steam System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The PG&E Design Class I non-ESF portion of the main steam system is designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) <u>Protection Against High Energy Pipe Rupture Effects</u>

The PG&E Design Class I non-ESF portion of the main steam system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) <u>Protection from Moderate Energy Pipe Rupture Effects – Outside Containment</u>

The PG&E Design Class I portion of the main steam system located outside containment is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) <u>Protection from Jet Impingement – Inside Containment</u>

The PG&E Design Class I portion of the main steam system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Protection from Flooding Effects – Outside Containment

The PG&E Design Class I portion of the main steam system located outside containment is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(6) Decay Heat Removal

The PG&E Design Class I portion of the main steam system is designed to remove decay heat from the RCS through the SG safety valves and by providing steam to power the AFW pump turbine.

(7) Main Steam Isolation

The MSIVs are designed to isolate automatically in the event of a main steam line break (MSLB) either upstream or downstream of the MSIVs to prevent uncontrolled steam release and limit the steam release to the contents of a single SG.

(8) Secondary Side Pressure Control

The main steam system is designed with safety valves to protect the system from overpressurization.

(9) Steam Flow Restriction

The main steam system is designed with flow restrictors that limit the steam flow in the event of a MSLB at any location on the steam line.

10.3.1.14 10 CFR 50.49 – Environmental Qualification

The PG&E Design Class I main steam system components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

10.3.1.15 10 CFR 50.55a(f) – Inservice Testing Requirements

ASME code components within the PG&E Design Class I portion of the main steam system are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.3.1.16 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components within the PG&E Design Class I portion of the main steam system are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.3.1.17 10 CFR 50.63 – Loss of All Alternating Current Power

In the event of a station blackout (SBO), positive isolation of the main steam system is required to control secondary system inventory. The PG&E Design Class I portion of the main steam system provides a means for removing decay heat from the RCS by discharging steam from the SGs to the atmosphere via the 10 percent atmospheric dump valves (refer to Section 10.4.4).

10.3.1.18 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main steam system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.3.1.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The main steam system provides instrumentation to monitor main steam flow and radiation release from the SG safety valves during and following an accident.

10.3.1.20 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The PG&E Design Class I display instrumentation is designed to include the noble gas effluent radiological monitor. The radiation monitoring system provides instrumentation to monitor venting from the SG safety valves during and following an accident.

10.3.1.21 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the main steam system.

10.3.2 SYSTEM DESCRIPTION

The arrangement of the equipment associated with the main steam system is shown in Figures 3.2-4 and 10.3-6. Steam from the four SGs is supplied to the turbine-generator (refer to Section 10.2).

Saturated steam from the four SGs passes through the containment wall in carbon steel pipes arranged to satisfy flexibility and PG&E Design Class I requirements. Each main steam line is anchored to the containment wall at the penetration.

The measured steam flow has a functional PG&E Design Class II application. The flow signal is used by the PG&E Design Class II three-element feedwater controller and as a PG&E Design Class II load index signal for the main feedwater pumps (refer to Section 7.7.2.7).

Steam flow restrictors are installed in each steam line inside the containment. The pressure drop at rated load between the SGs and the turbine throttle is approximately 40 psi. Steam flow is measured by monitoring dynamic head in nozzles inside the steam pipes. The nozzles, which are of smaller diameter than the main steam pipe, are located inside the containment near the SGs.

Connections are provided in the four main steam lines, between the containment and the isolation valves, for spring-loaded safety valves and power-operated relief valves, and (in two of the four) steam lines to the auxiliary feed pump drive turbine, as shown in Figures 3.2-4 and 10.3-6.

The steam supply to the AFW pump turbine is PG&E Design Class I because of the ESF requirements of the AFW system (refer to Section 6.5). The steam supply lines from two of the four SGs are interconnected upstream of the steam line stop valve to provide both redundancy and balanced steam flow. Both isolation and check valves in series in each of these lines provide the required valve redundancy that acts to prevent reverse flow.

The function of the MSIV is provided by a quick-acting isolation valve and a check valve installed in each main steam line. These valves are located outside of the containment structure and downstream of the safety valves. This design ensures that steam line isolation occurs for breaks either upstream or downstream of the valves. These check valves prevent reverse flow from an unfaulted SG in the event of a pipe break upstream of the check valves. Additional data on these valves are provided in Section 10.3.2.1 regarding a discussion of the capability of the main steam isolation and check valves to withstand closure loads following a postulated MSLB.

The main steam system is designed so that a failure of a main steam line at any point along its length, or a malfunction of a valve installed therein, or any consequential damage, will not:

(1) Reduce the flow capacity of the AFW system

(2) Render inoperable any ESF (i.e., controls, power or instrumentation cables, emergency core cooling, or containment heat removal piping)

(3) Cause gross failure of any other steam or feedwater line valve

(4) Initiate a LOCA

Discussion of containment integrity for an MSLB is presented in Chapters 6 and 15. Furthermore, an MSLB between the exterior of the containment and the quick-acting isolation valve will not compromise the effectiveness of any containment barrier other than the broken steam line itself. Since the MSIVs are a secondary barrier that serve to back up the SG tubes, containment leaktight integrity will not be degraded as a result of a steam line break in this case.

The steam lines and the shell-sides of the SGs are considered an extension of the containment boundary and, as such, are not to be damaged as a consequence of damage to the RCS. The SG shells and steam lines are, therefore, designed to be protected against RCS missiles (refer to Section 3.5.2.4).

Applicable design and quality code classifications are discussed in Chapter 3. The classification and applicable codes for the main steam system are identified in Table 3.2-3. Faults involving the main steam system are discussed in Sections 15.3.2 and 15.4.2.

The MSIVs can be operated manually from the control room as described in Section 10.3.3.4. There are also manual bypass valves around those air-operated MSIV bypass valves on main steam leads 2 and 3. These local manual bypass valves can be used to drain condensate accumulated in piping upstream of the MSIVs upon a loss of instrument air supply prior to the startup of the AFW pump turbine.

10.3.2.1 Capability of Main Steam Isolation and Check Valves to Withstand Closure Loads following a Postulated Main Steam Line Break

10.3.2.1.1 Summary

During the postulated event of a pipe rupture in the main steam system, the check and isolation valves close under loading conditions that are much more severe than those encountered during normal plant operation. The analyses presented here demonstrate that both the main steam line check and isolation valves are capable of successfully performing their functions during this event.

10.3.2.1.2 Results

Impact energy levels for the most severe pipe rupture conditions are given in Table 10.3-2. The highest level is 0.888×10^6 in-lb for the isolation valve disc. The disc is capable of absorbing energy levels exceeding twice this predicted value without developing excessive deflections. The check valve disc, which has the same capability, is subjected to lower energy levels.

The bearing stress at the valve seat is determined from the disc-to-seat reaction. The results are within the typical allowable stresses for this type of application.

For the most part, the tail link is not stressed beyond the elastic limit; where the elastic limit is exceeded, the incursion into the plastic range is slight. The maximum tail link deflection is determined to be 0.0425 inches. This deflection will not prevent proper valve closure.

The maximum shearing stress developed in the rockshaft is 21.5 ksi, well within the elastic range of the material. The deflection in the rockshaft will be insignificant.

10.3.2.1.3 Basic Criteria and Assumptions

The following criteria and assumptions were used in the analysis:

(1) The initial angle of the isolation and check valve discs are 80 and 70° from the closed position, respectively.

(2) The postulated break locations that were selected will result in the most severe disc impact energy for each valve. Postulated break locations are established and defined in Reference 2, page 3.6A-41.

(3) The postulated break type that will result in the most severe disc impact energy is used. Types of breaks considered include circumferential, longitudinal, and crack as defined in Reference 3. The circumferential break is used in this analysis.

(4) The ruptured pipe is assumed to separate to full flow area instantaneously. A discharge coefficient of 1 is conservatively assumed for flow through the break area.

(5) It is conservatively assumed that there is no obstruction to discharging flow from the break that would prevent maximum blowdown flow from being developed.

(6) Isolation valve trip is conservatively assumed to occur 0.5 seconds (minimum) after a pipe rupture. Evaluation of larger time delays between pipe rupture and disc release shows that the shorter time is a more severe

condition on the valve; and therefore, the shortest possible release time is used in the analysis.

(7) It is assumed that there is no frictional resistance to the valve rockshaft rotation; and that the pneumatic actuators offer no resistance to closure after a trip signal.

(8) Initial steam conditions used in the analysis are as follows:

Hot Standby:	Line pressure	=	1020 psia
	Line flow	=	0 lb/sec
Full Load:	Line pressure	=	800 psia
	Line flow	=	1010 lb/sec

Under a postulated pipe rupture, the maximum flow through the isolation valve occurs under a plant hot standby condition. This results in a maximum acceleration of the valve disc. For the check valve, the plant operating condition that will result in the maximum disc impact energy is full load.

10.3.2.1.4 Analysis

10.3.2.1.4.1 Maximum Disc Impact Energy

The check valve computer program used to solve the equations of motion for the valve disc to determine angular velocity and energy at impact is a modification of RELAP 3 (Reference 4). The modification consists of incorporating the equations of motion for the valve disc.

The equations incorporated into the program to mathematically describe the valve disc motion include the equations of motion, valve pressure drop as a function of flow rate, actuator return spring forces, and valve flow area as a function of disc position. Because of the similarity in construction, these equations are the same (except for spring forces) for both the isolation and check valves. The isolation valve calculations are initiated following a trip signal. For the check valve, initiation is when the flow reverses in the pipe creating forces to close the disc.

The disc angular acceleration and velocity and the maximum disc impact energy are calculated as a function of the torque acting on the disc. This torque is comprised of gravitational, fluid flow, actuator, frictional, and viscous components. In this analysis, the frictional and viscous torque components act to delay the closure and thus are conservatively neglected. The gravity torque is a function of disc position and the actuator torque is a function of spring displacement. The fluid flow torque is caused by pressure differential across the disc. The pressure differential across the disc, in the non-choking flow region, is the frictional pressure drop across the disc calculated from the valve loss coefficients established by the valve manufacturer (Schutte and Koerting

Company). To determine the pressure drop across the disc in the choking flow region, a static pressure difference in volumes upstream and downstream of the disc is used.

10.3.2.1.5 Component Analysis

10.3.2.1.5.1 Load Generation

The loads acting on the valve components are generated by the disc angular velocity, disc angular acceleration, and the kinetic energy developed in the disc at instant of impact. These quantities are given in Table 10.3-2. The maximum of these values for the isolation of check valves were used in the analysis.

10.3.2.1.5.2 Disc Analysis

Analysis of disc closure is accomplished by an equivalent static method whereby the disc is loaded with a pseudoloading which approximates the inertia forces acting on the disc. The magnitude of this loading is varied and a relationship between the strain energy developed in the disc and the pseudoloading is established. The maximum displacements experienced by the disc are taken to correspond to the point at which the strain energy developed under the pseudoloading equals the kinetic energy at instant of impact.

Subsequently, a reanalysis was performed for evaluating an alternative valve disc material with lower material strengths.

10.3.2.1.5.3 Valve Body Seat Area Analysis

The valve body seat area is analyzed by determining the reaction of the valve seat due to the impact of the disc. This reaction is found from the load-energy relationship derived in the analysis for the valve disc as described above. The load corresponding

to the initial kinetic energy in the disc is determined from this load-energy relationship. The reaction at the valve disc is determined by dividing this load by the circumferential area of the valve seat.

10.3.2.1.5.4 Tail Link Analysis

The critical loading conditions on the tail link occur during travel when the tail link is acted upon by centrifugal forces. In this mode the tail link structure may be considered statically determinate with the centrifugal force resultant applied at the rock shaft and reacted at the disc connection. The maximum loads in the travel mode occur just prior to disc impact, and since the tail link structure is taken as statically determinate, the moment and force resultants throughout for this condition are determined from equilibrium considerations. With the axial and moment resultants known throughout the tail link, deflections are determined by dividing the structure into an appropriate number of sections, then determining and summing the deflections of these individual sections.

10.3.2.1.5.5 Rockshaft Analysis

The design loading condition occurs just prior to valve closure when the rockshaft sees the peak centrifugal forces developed in the tail link. These centrifugal forces are applied as shearing forces to the rockshaft. No coupling between this loading condition and the torque carried by the rockshaft in the open position is considered, since this torque diminishes as the valves close and is zero at instant of valve closure.

10.3.3 SAFETY EVALUATION

10.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The main steam lines, together with their supports and structures between each SG and its associated isolation valves (including the check valves), are PG&E Design Class I.

The main steam lines are designed to perform their safety functions under the effects of earthquakes (refer to Section 3.7.2.2.1.3). The main steam system downstream of the MSIVs is PG&E Design Class II, however the main steam piping downstream of the MSIVs up to the column line G pipe anchor is considered PG&E QA Class S, and seismic analyses of piping up to the column line G pipe anchor have determined that a seismic event will not prevent the MSIVs from performing their PG&E Design Class I isolation function.

The main steam lines are designed to perform their safety functions under the effects of floods and tsunamis (refer to Section 2.4.3.2).

The containment structure, pipeway structure, and auxiliary building, which contain the main steam system's PG&E Design Class I SSCs, are PG&E Design Class I (refer to Section 3.8). These buildings, or applicable portions thereof, are designed to withstand the effects of winds (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). These designs protect the main steam system, ensuring its safety functions will be performed.

Portions of main steam lines, including the MSIVs, are located outside and on the roof of the auxiliary building and are partially resistant to tornadoes, however, the capability of the system to support plant safe shutdown is maintained (refer to Section 3.3.2.5.2.7).

10.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The main steam system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.3.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Each DCPP unit can supply portions of the other unit's auxiliary steam from its PG&E Design Class II portion of the main steam system downstream of the MSIVs. Check valves in the supply lines prevent cross-flow of the main steam if this feature is utilized. Failure of this check valve would not affect either unit because both units operate within the same design parameters.

The PG&E Design Class I portion of the main steam system is not affected by this feature.

10.3.3.4 General Design Criterion 11, 1967 – Control Room

The MSIVs can be operated manually from the control room. The MSIVs have remote-manual, air-operated bypass valves for the pressure equalization that is necessary to open the valves. The bypass valves are operated from the control room and automatically close on the same signals that automatically close the MSIVs.

Position indication is provided on the main control board for all MSIVs and bypass valves. Additionally, the main control board provides indications of main steam flow and SG pressure.

If access to the control room is lost, necessary main steam system valves can be operated locally with SG pressure indicated on the HSP.

10.3.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The MSIVs automatically close on high negative steam line pressure rate, low steam line pressure, or on a high-high containment pressure signal. Instrumentation and controls for the main steam system are discussed in Sections 6.2.4, 7.3, and 9.3.1.2.2.

Refer to Section 10.3.3.7 for radiation monitoring instrumentation.

10.3.3.6 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The main steam system monitors steam pressure and provides the signal to engineered safety features actuation system (ESFAS) (refer to Section 7.3).

10.3.3.7 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The radiation monitoring system continuously monitors the main steam system (refer to Section 11.4.2.1.2.1).

Steam generated in the SGs is not normally radioactive. However, in the event of primary-to-secondary system leakage due to a SG tube leak, it is possible for the main steam to become radioactively contaminated. A full discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentration of radioactive contaminants, means of detection of radioactive contamination, anticipated releases to the environment, and limiting conditions for operation, is included in Sections 7.5.2.3, 11.1.6, 11.4.2.1.2.1, and 15.5.

10.3.3.8 General Design Criterion 21, 1967 – Single Failure Definition

The instrumentation and control circuits for steam line isolation (refer to Section 7.3) are redundant in the sense that a single failure cannot prevent isolation. Each MSIV is opened by air and closes when either of the solenoid valves (powered from separate Class 1E 125-Vdc sources) in its vent line is energized, releasing the air.

The instrumentation and control circuits for the main steam system pressure provided to ESFAS are redundant in that a single failure cannot prevent the SI signal actuation. Each steam header employs two-out-of-three logic for its signal.

The main steam supply to the turbine-driven AFW pump is provided from both the number 2 and number 3 steam headers.

10.3.3.9 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the main steam system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

10.3.3.10 General Design Criterion 49, 1967 – Containment Design Basis

The main steam line containment penetrations are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

10.3.3.11 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The main steam system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4.1.4.

10.3.3.12 General Design Criterion 57, 1971 – Closed System Isolation Valves

The main steam system containment penetrations and isolation valves are part of the CIS. Refer to Section 6.2.4 and Table 6.2.-39 for penetration details.

10.3.3.13 Main Steam System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the PG&E Design Class I non-ESF portion of the main steam system from the effects of missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the main steam system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I non-ESF portion of the main steam system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the main steam system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the main steam system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

(6) Decay Heat Removal

The main steam system provides means for removing decay heat from the RCS by discharging steam from the SGs to the atmosphere through the SG safety valves and also by providing steam to power the AFW pump turbine (refer to Sections 6.5.2 and 7.4.2).

(7) Main Steam Isolation

The MSIVs and check valves (MSIV/CV) are located outside of the containment structure and downstream of the safety valves. The fast-acting isolation valves are provided in each main steam line and will fully close within 10 seconds of a large steam line break. This design ensures that steam line isolation occurs for breaks either upstream or downstream of the valves. The MSIV/CV are credited to prevent reverse flow from the steamline header and intact SGs. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one SG would blow down even if one of the isolation valves fails to close. Cases that postulate the failure of the MSIV/CV are discussed in Section 6.2D.4.1.4. The MSIVs automatically close on high negative steam line pressure rate, low steam line pressure, or on a high-high containment pressure signal and can also be operated from the control room (refer to Sections 10.3.3.4 and 10.3.3.5).

Uncontrolled steam release as a result of a main steam line failure is therefore limited to the contents of one SG, thus keeping the related effect upon the reactor core within the prescribed bounds. (The main steam line rupture event is discussed in detail in Appendix 6.2D and Sections 15.3.2 and 15.4.2.) This results in the need for both isolation valves and check valves, as well as special design considerations for the main steam lines themselves. These considerations are necessary to ensure that damage to a portion of one steam line does not result in damage to the corresponding portion of the other steam lines or the other SGs. They are covered in detail in the MSLB discussion (refer to Section 15.4.2).

(8) <u>Secondary Side Pressure Control</u>

Five spring loaded safety valves are installed on each main steam line, upstream of the MSIVs, to protect the main steam system from overpressurization. The pressure setpoints for these valves are progressively set from 1065 psig to 1115 psig as shown in Table 10.1-1. Refer to Section 3.9.2.2.5 for additional discussion regarding the safety valves.

(9) <u>Steam Flow Restriction</u>

Each main steam line includes an in-line 16-inch diameter flow restrictor that acts to limit the maximum flow and the resulting thrust forces created by a steam line break. The flow restrictors are discussed in more detail in Sections 5.5.4 and 15.4.2. These flow restrictors are separate from the integral flow restrictors in the SG outlet nozzles. Refer to Section 5.1.8.17(6) for a discussion of the SG integral flow restrictor.

10.3.3.14 10 CFR 50.49 – Environmental Qualification

Main steam system components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. The affected equipment is listed on the EQ Master List. Main steam EQ components include solenoid valves and position switches for the MSIVs and MSIV bypass valves, and steam flow and pressure transmitters. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment.

10.3.3.15 10 CFR 50.55a(f) – Inservice Testing Requirements

Main steam system components that are within the inservice testing (IST) program are the MSIVs, MSIV bypass valves, the isolation valves for the 10% steam dumps (the steam dump valves themselves are discussed in Section 10.4.4), and the safety valves.

The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.3.3.16 10 CFR 50.55a(g) – Inservice Inspection Requirements

The main steam system piping has a periodic inservice inspection (ISI) program in accordance with the ASME BPVC Section XI.

10.3.3.17 10 CFR 50.63 – Loss of All Alternating Current Power

In the event of a SBO, closure of the main steam isolation valves provides positive isolation of the main steam system. Refer to Section 10.4.4 for evaluation of the 10 percent atmospheric dump valves following a SBO.

Refer to Section 8.3.1.6 for further discussion of SBO.

10.3.3.18 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main steam system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.3.3.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Category 2 main steam flow indication and radiation monitoring for the vents from the SG safety valves are provided in the control room for Regulatory Guide 1.97, Revision 3 monitoring (refer to Table 7.5-6).

10.3.3.20 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The PG&E Design Class I display instrumentation for main steam line activity monitoring when venting from the SG safety valves during and following an accident is provided and is described in Sections 7.5.2.3 and 11.4.2.1.2.1.

10.3.3.21 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the flow-accelerated corrosion (FAC) monitoring program for all plant systems, including the main steam system.

10.3.4 TESTS AND INSPECTIONS

The piping from the SG, up to and including the main steam line isolation valves, is equipped with removable insulation for ISI of welds. The tests and inspections that apply to the main steam line isolation valves are in accordance with the DCPP Technical Specifications (Reference 1). Main steam line isolation valves are tested periodically to verify their ability to close within the required time (refer to Section 7.3 for a discussion of the response times for the steam line isolation signal).

Preoperational and startup testing requirements applicable to the main steam system are discussed in Chapter 14.

Since the major components of the SPCS are accessible during normal power operation, leakage from the valves located upstream of the MSIVs is monitored by routine visual inspection by the operators.

The MSIVs, and the valves upstream of them and outside the containment, are designed and packed to have the capability of limiting gland leakage along the stem to no more than one cubic centimeter of water per hour per inch of stem diameter, when subjected to a hydrostatic test pressure of 1100 psig, or 0.03 scf of air per hour per inch of stem diameter with a differential pressure of 80 psi. They are designed to have the capability to limit the valve seat leakage rate to 0.1 scf per hour per inch of seat diameter, when subjected to a pneumatic pressure of 80 psig. Table 10.3-1 summarizes the potential leakages for valves located upstream of the steam line isolation valves, and lists the leak rates measured through these leak paths during initial plant startup testing.

However, since the secondary system is a closed system inside containment whose integrity is not damaged by a LOCA, the offsite dose consequences via the leak paths identified in Table 10.3-1 are small when compared to the consequences from the containment atmosphere leakage assumed in the offsite dose analysis. Hence, pursuant to Table 6.2-39, there are no local leak rate limits established for these leakage paths, since in accordance with 10 CFR Part 50 Appendix J, this leakage is not required to be measured.

10.3.5 WATER CHEMISTRY

The secondary water chemistry control program is discussed in Section 5.5.2.3.5. SG blowdown for chemistry control is discussed in Section 10.4.8. The main steam sampling system is discussed in Section 9.3. Chemical treatment of the secondary system water for corrosion control is discussed in Section 10.4.9.

10.3.6 INSTRUMENTATION APPLICATIONS

Instrumentation for the main steam system is discussed in Sections 10.3.3.4 and 10.3.3.5.

10.3.7 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

2. Nuclear Services Corporation, Evaluation for Effects of Postulated Pipe Break Outside Containment for Diablo Canyon Unit 1, Revision 2, June 26, 1974.

3. Letter (Docket Nos. 50-275 and 50-323) from A. Giambusso of the U.S. Atomic Energy Commission to F.T. Searls of the Pacific Gas and Electric Company, dated December 18, 1972, including the attachment "General Information Required for Consideration of the Effects of Piping System Break Outside Containment."

4. W.H. Rettig, et al, "RELAP 3 - A Computer Program for Reactor Blowdown Analysis," IN-1321, June 1970. Also Supplement of June 1971.

10.3.8 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

The main condenser provides a heat sink and collection volume for steam and condensate discharged from the main turbine, feedwater pump turbines, TBS, feedwater heater drains, and other miscellaneous flows, drains, and vents.

10.4.1.1 Design Bases

The main condenser is classified as PG&E Design Class II. There are no regulatory requirements associated with the main condenser. Radioactive leak detection is discussed in Section 10.4.2.

10.4.1.2 System Description

The main condenser is designed to condense full load steam and maintain a nominal absolute pressure of 1.71 inches of mercury at 85 percent cleanliness. Sufficient surface (618,150 square feet) is provided to condense TBS steam (up to 40 percent of maximum calculated capability flow), following a load reduction, or under controlled startup conditions, or from residual and decay heat at shutdown.

The condenser hotwells are sized to provide adequate storage of water (138,000 gallons) to allow for the water lost to the atmosphere and "shrinkage" on a 50 percent load reduction. The condensate leaving the hotwells is deaerated to 0.005 cc/liter dissolved oxygen level. The main condenser is provided with a means of detecting saltwater leakage.

During operation, air is removed from the condenser by steam jet air ejectors and discharged to the plant vent. The discharged air is continuously monitored for radioactivity. No control functions are associated with this radiation monitor. For drawing initial vacuum, the condenser is evacuated by a wet-type rotary vacuum pump which discharges air to the atmosphere. The condenser vacuum pump may also be placed into service in the event of degraded condenser vacuum. Refer to Section 10.4.2 for a discussion of the main condenser evacuation system (MCES).

The main condensing surface is mounted beneath the low-pressure turbine elements in two shells with interconnected steam spaces. The tubes are arranged parallel to the turbine shaft. The performance data for both the Unit 1 and Unit 2 condensers are summarized in Table 10.4-1.

The following materials are used in the condenser:

(1) Shell and tube supports - carbon steel, ASTM A285, Grade C

(2) Tubesheets - 90-10 copper nickel, ASTM B171 (with corrosion-resistant coating on the saltwater side)

(3) Water boxes - carbon steel, ASTM A285, Grade C, lined with corrosion resistant coating on the saltwater side

(4) Tubes - titanium

The condenser will condense up to 40 percent of the full load main steam flow during a load reduction, startup, or shutdown. As discussed in Chapter 15, the SG safety valves protect the NSSS from overpressure if the condenser is not available or if the steam flow exceeds the capacity of the condenser. The secondary system is normally not radioactive. However, in the event of primary-to-secondary leakage through leaking SG tubes, it is possible for the main steam to become radioactively contaminated. A discussion of the assumed leakage rates, treatment methods, and calculated activity levels is included in Section 11.1.6, and an inventory of radionuclides in the condenser for an assumed leak rate is shown in Table 11.1-27.

10.4.1.3 Safety Evaluation

The main condenser is classified as PG&E Design Class II. There are no regulatory requirements associated with the main condenser. Radioactive leak detection is discussed in Section 10.4.2.

10.4.1.4 Tests and Inspections

Tests and inspections of the main condenser are done in accordance with plant procedures.

10.4.1.5 Instrumentation Applications

Instrumentation is provided to monitor and control main condenser operation.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The MCES removes noncondensable gases from the main condenser during plant startup, cooldown, and normal operation. The system is classified as PG&E Design Class II.

10.4.2.1 Design Bases

10.4.2.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The MCES is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

10.4.2.1.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident-Monitoring Instrumentation:

Position (1) – The MCES is designed with noble gas effluent monitors that are installed with an extended range designed to function during accident conditions.

Position (2) – The MCES is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

10.4.2.2 System Description

The MCES consists of a wet-type rotary vacuum pump and steam jet air ejectors. The vacuum pump is common to both units and is used to draw an initial vacuum in the condenser of either unit and may be used during degraded vacuum conditions. The steam jet air ejectors are used after the initial pumpdown and are designed to remove air that may degrade the ability of the condenser to maintain a nominal absolute pressure of 1.71 inches of mercury, as described in Section 10.4.1.2.

The wet-type rotary vacuum pump has a capacity of approximately 7000 cubic feet per minute.

The steam jet air ejector system consists of two stages of steam jets mounted on a combined inter-after surface condenser. The air ejector system is designed to remove 360 pounds per hour of air saturated with water vapor at 71.5°F, and a suction pressure of 1 inch of mercury absolute pressure when supplied with steam at 85 psig. The first stage consists of eight 25 percent capacity jets and the second stage consists of twin 100 percent capacity jets.

Refer to Section 5.5.2 for information on PG&E's implementation of Electric Power Research Institute primary-to-secondary leak guidelines.

10.4.2.3 Safety Evaluation

10.4.2.3.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Air is discharged from the vacuum pump through a local vent. During vacuum pump operation, grab samples are taken at the local vent in support of the Radioactive Effluent Controls Program. In addition, evaluations have been performed that demonstrate potential radioactive discharges remain within 10 CFR Part 20 limits. Noncondensables vented from the steam jet air ejectors while the plant is at power operation are discharged through the plant vent that is continuously monitored for radioactivity. Further discussion of releases due to SG leakage and the radiation monitoring of the plant vent is given in Sections 7.5.2.3, 9.4.2, 11.1.6, and 11.4.

10.4.2.3.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident-Monitoring Instrumentation:

Position (1) – Extended range noble gas effluent monitoring is installed in the plant vent, which includes exhaust from the steam jet air ejectors, and is designed to function during accident conditions. Refer to Section 9.4.2 for information on the plant vent and Figures 3.2-2 and 3.2-23 for a depiction of steam jet air ejector after-condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations that may be present in the gaseous effluent being discharged to the environment from the plant vent, which includes the steam jet air ejector exhaust, under accident and post-accident conditions. The technical support center laboratory is available for onsite testing of the air samples. Refer to Section 9.4.2 for information on the plant vent and Figures 3.2-2 and 3.2-23 for a depiction of steam jet air ejector after-condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

10.4.2.4 Tests and Inspections

Tests and inspections of the MCES are done in accordance with plant procedures.

10.4.2.5 Instrumentation Applications

Instrumentation is provided to monitor and control MCES operation.

10.4.3 TURBINE GLAND SEALING SYSTEM

The turbine gland sealing system provides shaft sealing for the main turbine and feedwater pump turbine.

10.4.3.1 Design Bases

The turbine gland sealing system is designed to prevent the leakage of air into, or steam out of, the turbines along the turbine shaft. The system has no PG&E Design Class I functions and is classified as PG&E Design Class II.

10.4.3.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The turbine gland sealing system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

10.4.3.1.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident-Monitoring Instrumentation:

Position (1) - Item II.F.1, Position (1) requires monitoring of post-accident effluent noble gas releases from the turbine gland sealing system.

Position (2) - Item II.F.1, Position (2) requires monitoring of post-accident effluent radioactive iodine and particulate releases from the turbine gland sealing system.

10.4.3.2 System Description

The turbine glands are of the labyrinth type. When the unit is being started, and partially during normal operation, steam is supplied to the gland header from the main steam line to seal the high-pressure and low-pressure turbine glands. The auxiliary boiler also can be used to supply sealing steam during startup. When the turbine is operating under load, the steam pressure inside the high-pressure turbine increases and steam leaks outward toward the rotor ends. The leakage from the high-pressure glands partially supplies the steam requirements for the low-pressure glands, while the remainder is furnished by the main steam gland regulator. Adequate steam pressure is maintained in the gland area at all times to prevent the leakage of air into, or steam out of, the turbine along the turbine shaft.

At normal operating conditions, the exhaust from the gland seals is approximately 3000 pounds per hour of air saturated with water vapor at 150°F. The gland steam condenser maintains a pressure slightly below atmosphere in the gland leak-off system to prevent the escape of steam from the glands. The air and noncondensable gases from the turbine gland seal condenser are exhausted to the plant vent, which is continuously monitored (refer to Section 11.4.2.1.2.1).

10.4.3.3 Safety Evaluation

10.4.3.3.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The turbine gland sealing system has no PG&E Design Class I function. In the event of SG leakage and continued plant operation, the gland sealing system prevents the release of radioactive steam to the turbine building. If gland seals are lost due to a malfunction of the system, a small amount of steam could be released depending on the type of equipment malfunction. Upon the loss of gland sealing steam, the turbine would be tripped to prevent seal or rotor damage. A turbine trip would prevent additional radioactive steam from entering the turbine.

The air and noncondensable gases from the gland seal condenser are routed to the plant vent (refer to Sections 9.4.2 and 11.4.2.1.2.1). In the event that the gland steam becomes contaminated, it will be detected by radiation detectors located in the plant vent (normal range and redundant normal range radiation monitors). The turbine building is not monitored for leakage from the glands. Details of the radiological evaluation of the system are included in Section 11.3.2.3.

10.4.3.3.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident-Monitoring Instrumentation:

Position (1) - Radiation detection instruments are provided in the plant vent to monitor post-accident effluent noble gas releases from the turbine gland sealing system. Refer to Section 9.4.2 for information on the plant vent and Figure 3.2-23 for a depiction of turbine gland steam condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

Position (2) - Radiation detection instruments are provided in the plant vent to monitor post-accident effluent radioactive iodine and particulate releases from the turbine gland sealing system. Refer to Section 9.4.2 for information on the plant vent and Figure 3.2-23 for a depiction of turbine gland steam condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

10.4.4 TURBINE BYPASS SYSTEM

The TBS bypasses main steam directly to the main condenser and atmosphere, depending on the required capacity, during the emergency condition caused by a sudden load reduction by the turbine-generator or turbine trip, and during plant startup and shutdown.

10.4.4.1 Design Bases

Of the 25 turbine bypass valves (refer to Section 10.4.4.2), only the four 10 percent atmospheric dump valves have a safety function (refer to Section 10.4.4.3.8). Therefore, the design bases in this section apply only to these valves and their associated upstream piping systems.

10.4.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The 10 percent atmospheric dump valves are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

10.4.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The 10 percent atmospheric dump valves are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.4.1.3 General Design Criterion 11, 1967 – Control Room

The 10 percent atmospheric dump valves are designed to or contain instrumentation that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.4.4.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the 10 percent atmospheric dump valves’ variables within prescribed operating ranges.

10.4.4.1.5 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the TBS (10 percent atmospheric dump valves) is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.4.4.1.6 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping system associated with the 10 percent atmospheric dump valves that penetrates containment is provided with leakage detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.4.1.7 General Design Criterion 57, 1971 – Closed System Isolation Valves

The main steam system headers associated with the 10 percent atmospheric dump valves are designed such that each line that penetrates containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere has at least one containment isolation valve which is either automatic or locked closed or capable of remote-manual operation. This valve is outside containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve.

10.4.4.1.8 Turbine Bypass System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) <u>Protection from High Energy Pipe Rupture Effects</u>

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) <u>Protection from Moderate Energy Pipe Rupture Effects</u>

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) <u>Protection from Flooding Effects</u>

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) <u>Reactor Coolant System Cooldown</u>

The 10 percent atmospheric dump valves are designed to provide a method for RCS cooldown.

10.4.4.1.9 10 CFR 50.55a(f) – Inservice Testing Requirements

The 10 percent atmospheric dump valves are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.4.4.1.10 10 CFR 50.55a(g) – Inservice Inspection Requirements

The 10 percent atmospheric dump valves are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.4.4.1.11 10 CFR 50.63 – Loss of All Alternating Current Power

The 10 percent atmospheric dump valves are required to perform their function of heat removal from the secondary side of the steam generators to maintain the unit in Hot Standby (Mode 3) in the event of a SBO.

10.4.4.1.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 10 percent atmospheric dump valves are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.4.4.2 System Description

The TBS consists of 25 power relief valves. Four of these valves (10 percent dump valves) take steam from each main steam line and discharge to the atmosphere. The remaining 21 valves take steam from the dump headers (connected to all main steam lines)and discharge either into spray distribution headers in the condenser (40 percent dump valves) or to the atmosphere (35 percent dump valves). The system thus provides an artificial load on the RCS during the emergency condition of a sudden load reduction by the turbine-generator or a turbine trip (four of the 40 percent dump valves are used during cooldown).

The valve groups are opened in the following sequence:

(1) Cooldown valves (four of twelve 40 percent dump valves)

(2) Bypass valves (remaining eight of twelve 40 percent dump valves)

NOTE: Plant capability is provided to use all 12 valves for cooldown during Mode 3 after boration to cold shutdown conditions.

(3) Atmospheric relief valves (nine 35 percent atmospheric dump valves downstream of the MSIVs)

(4) Atmospheric relief valves (four 10 percent atmospheric dump valves upstream of the MSIVs)

NOTE: Group 4 of the atmospheric dump valves are set at a lower pressure than the spring-loaded safety valves.

The TBS is thus designed with a capacity to bypass a range of approximately 66 to 79 percent of the full load steam flow over the range of full load operating conditions to the main condenser and the atmosphere combined. The exact capacities of these relief valves depend on the full load operating conditions. Valve groups 1, 2, and 3 are credited in determining this capacity. The steam dump capacity to the main condenser alone (groups 1 and 2) has a range of approximately 35 to 41 percent of the full load steam flow over the range of full load operating conditions.

The capacity of the TBS, combined with the 10 percent step-load-change characteristics of the reactor, provides the capability of accepting a sudden load reduction of up to 50 percent, without reactor trip or operation of the spring-loaded safety valves or 10 percent atmospheric dump valves.

The total amount of steam released to the atmosphere during a loss of generator external load assuming that the condenser is not available for steam dump is discussed in Section 15.5.10.2.

With the exception of group 4 of the atmospheric dump valves, the TBS is not essential to the safe operation of the plant; it is required to give the plant flexibility of operation and a controlled cooldown. The SG safety valves provide relieving capacity during a period when all valves are out of service (refer to Section 10.3.2).

Failure of the 40 percent dump valves, the 35 percent atmospheric dump valves downstream of the MSIVs, or any pipe downstream of the MSIVs could result in a rapid cooldown and depressurization of the SGs until the MSIVs close on high negative steam line pressure rate or low steam line pressure signals. The transients and radiological consequences associated with such a failure would not be as severe as the double-ended severance of a main steam line, as discussed in Section 15.5.18. Failure of any of these components (or pipe associated with them) downstream of the MSIVs could not cause overpressurization of a SG because of the location of the spring-loaded safety valves upstream of the MSIVs.

The TBS has been analyzed for potential effects of piping rupture on nearby safety-related equipment. Details of this analysis are presented in Section 3.6.4.

10.4.4.2.1 Design Codes and Standards

The piping and valves associated with the 40 percent and 35 percent dump valves are classified as PG&E Design Class II because they are not required for RCS cooldown, as discussed in Section 10.4.4.3.

The 10 percent atmospheric dump valves and associated upstream piping are classified as PG&E Design Class I because they are required for RCS cooldown, as discussed in Section 10.4.4.3.8.

Applicable codes and standards for piping, valves, and fittings are discussed in Section 3.2.

10.4.4.3 Safety Evaluation

10.4.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The 10 percent atmospheric dump valves are PG&E Design Class I components and are located either on the roof of the PG&E Design Class I auxiliary building at elevation 143 feet (steam leads 3 and 4) or on a support structure external to the containment at elevation 112 feet-6 inches (steam leads 1 and 2). These elevations are above the level affected by floods and tsunamis.

PG&E Design Class I SSCs in locations exposed to the weather are evaluated against tornado-related effects including impact by tornado-induced missiles. Refer to Section 3.3.2.3 for the results of the evaluation.

The 10 percent atmospheric dump valves are required to function following a Design Earthquake, Double Design Earthquake, and Hosgri Earthquake (refer to Sections 3.7.1 and 3.7.6).

10.4.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The 10 percent atmospheric dump valves are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.4.4.3.3 General Design Criterion 11, 1967 – Control Room

The 10 percent atmospheric dump valves can be controlled manually from within the control room in order to maintain safe operational status of the plant. In the event that control room access is lost due to fire or other causes, the valves can be controlled manually from the HSP (refer to Section 7.4.2.1.2.3).

10.4.4.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation for manually operating the 10 percent atmospheric dump valves is provided in the main control room, at the HSP, and locally at the valve (refer to Section 7.4.2.1.2.3). Valve position indication is provided on the emergency response facility data system (ERFDS) (refer to Section 7.5.2.9).

10.4.4.3.5 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the TBS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

10.4.4.3.6 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The 10 percent atmospheric dump valves, required for containment closure, are periodically tested for operability. Testing of the components required for the CIS is discussed in Section 6.2.4.

10.4.4.3.7 General Design Criterion 57, 1971 – Closed System Isolation Valves

The containment penetrations associated with the 10 percent atmospheric dump valves comply with the requirements of GDC 57, 1971, as described in Section 6.2.4 and Table 6.2-39.

10.4.4.3.8 Turbine Bypass System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) from the effects of missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the TBS (10 percent atmospheric dump valves) from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection for the PG&E Design Class I TBS (10 percent atmospheric dump valves) from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection for the PG&E Design Class I TBS (10 percent atmospheric dump valves) from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

(5) Reactor Coolant System Cooldown

The 10 percent atmospheric dump valves provide a means for plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the 10 percent atmospheric dump valves, in conjunction with the AFW system, permit the plant to be cooled down from the pressure setpoint of the lowest-set main steam safety valves to the point where the residual heat removal system can be placed in service. In the event of a steam generator tube rupture event in conjunction with loss of offsite power, the 10 percent atmospheric dump valves are used to cool down the RCS to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set main steam safety valve.

With the loss of both the normal air supply and the backup nitrogen supply to the 10 percent atmospheric dump valves, the normal supplies are blocked and the PG&E Design Class I backup air bottle system is activated (refer to Section 9.3.1.2). With the backup air bottle system activated, control of the valves is remote manual via the PG&E Design Class I control circuit from the control room ensuring the valves can cooldown the RCS.

10.4.4.3.9 10 CFR 50.55a(f) – Inservice Testing Requirements

The TBS components that are within the IST program are the four 10 percent atmospheric dump valves.

The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.4.4.3.10 10 CFR 50.55a(g) – Inservice Inspection Requirements

The 10 percent atmospheric dump valves have a periodic ISI program in accordance with the ASME BPVC Section XI (refer to Section 5.2.3.15).

10.4.4.3.11 10 CFR 50.63 – Loss of All Alternating Current Power

During an SBO, decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the SGs and discharged to the atmosphere through the 10 percent atmospheric dump valves. The 10 percent atmospheric dump valves have adequate capacity for decay heat removal to maintain the unit in Hot Standby for the 4 hour SBO coping duration.

Refer to Section 8.3.1.6 for further discussion of station blackout.

10.4.4.3.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 10 percent atmospheric dump valves are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.4.4 Tests and Inspections

Local test facilities for the bypass flow control valves are not provided. The 40 percent dump valves and the 35 percent dump valves are PG&E Design Class II and are tested at reactor low power levels.

Each 10 percent atmospheric dump valve , associated block valve, and associated remote manual controls, including the backup air bottles, is demonstrated operable on a frequency interval required by the Technical Specifications.

Additionally, each 10 percent atmospheric dump block valve is verified open at least once per 31 days

Should evidence indicate that radioactivity is being released as a result of leakage through these valves during the post-accident recovery period, action such as tightening packing will be taken to eliminate the source.

10.4.4.5 Instrumentation Applications

During normal operating transients for which the plant is designed, the TBS is automatically regulated by the reactor coolant temperature control system to maintain the programmed coolant temperature.

When a transient results in a plant trip, the operator transfers bypass control to the pressure control mode and regulates the system to maintain no-load steam pressure. Lower pressures can be maintained automatically by adjustment of the pressure setpoint. During a plant cooldown, the bypass system is manually controlled to achieve the required cooling rate. This is accomplished by manual adjustment of the pressure setpoint in the control room and requires a minimum operation of four bypass valves to the condenser.

Refer to Section 10.4.4.3.4 for additional information on instrumentation and controls.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system provides the heat sink required for removal of waste heat in the power plant's thermal cycle. The system has the principal function of removing heat by absorbing this energy in the main condenser.

10.4.5.1 Design Bases

10.4.5.1.1 Circulating Water System Safety Function Requirements

(1) Protection from Flooding Effects

The flooding effects from a circulating water system pipe rupture do not prevent essential equipment from safely shutting down and maintaining shutdown conditions of the reactor.

10.4.5.2 System Description

The circulating water system is designed to provide cooling water necessary to condense the steam entering the main condenser. The system also serves the intake coolers, condensate cooler, and service cooling water heat exchangers. The design temperature rise in the circulating water system at full load operation is 18°F. The design flow per unit is nominally 862,000 gpm.

The circulating water system is classified as PG&E Design Class II.

Condenser circulating water is seawater from the Pacific Ocean. The ocean water level normally varies between zero and +6 feet mean lower low water (MLLW) datum. Mean sea level (MSL) zero is equivalent to +2.6 feet MLLW.

A curtain wall at the front of the intake structure limits the amount of floating debris entering the intake structure. Bar racks near the front of the intake structure intercept large submerged debris. The bar racks have 3/8-inch thick bars at 3-3/8 inch centers. Traveling screens intercept all material larger than the screen mesh opening (3/8 inch clear square openings).

The total flow in each unit's circulating water system is nominally 862,000 gpm, which is pumped by two circulating water pumps per unit through two circulating water conduits per unit to the condenser inlet water boxes. Each pump has a discharge valve and bypass line around the valve. Approximately 4000 gpm of the circulating water flow is used per unit to cool the service cooling water heat exchangers and 1000 gpm to cool the pump motor cooling water.

At the intake structure, each circulating water system consists of two circulating water pumps with 12-kV motors cooled by an air-to-water heat exchanger. The cooling water is provided from a closed-loop cooling system.

The chlorination system provides chemical treatment of the circulating water to control macro and micro fouling in the intake tunnels, piping, and the condenser tubes. The system is used as needed.

The chlorination system, which is shown as part of Figure 3.2-17, provides an oxidizing biocide to the suction of the circulating water pumps for control of macro and micro fouling. Liquid sodium hypochlorite and a supplemental chemical are stored in tanks at the intake structure (common to both units). Adequate valving is provided for isolating any of the tanks from the system. Each tank is within a containment tank sized to contain the entire contents of the storage tank. When chlorination is required (based on a time schedule), the chemicals are injected via metering pumps and injected into the intake structure. In addition, dechlorinating injections are made between the outlet of the main condenser and the discharge structure as required to ensure national pollutant discharge elimination system (NPDES) permit requirements are met. Concentrations of chlorine in the circulation water system outfall are discussed in detail in Reference 1 and the NPDES permit.

The circulating water pumps are not required for safety of the units. Dependable pump operation is necessary, however, for reliable operation of electric generating plants and provisions to ensure their operation are incorporated in the design.

10.4.5.3 Safety Evaluation

10.4.5.3.1 Circulating Water System Safety Function Requirements

(1) <u>Protection from Flooding Effects</u>

The failure of circulating water system piping is evaluated for the effects of flooding on PG&E Design Class I essential safe shutdown equipment located in the turbine building. The provisions taken to provide protection for the safe shutdown equipment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

Due to the low operating pressure of the circulating water system, the probability of a line, expansion joint, or waterbox failure is very low. The differential head across the circulating water pumps at shutoff is a nominal 160 feet. At high tide, the pump discharge head at shutoff would be 163.4 feet (refer to Section 10.4.5.2), measured at elevation zero, MSL datum. However, provisions exist in the design of the circulating water system that prevent the circulating water pumps from operating at shutoff head.

The design of the inlet and outlet of the circulating water to the condenser consists of several components. The circulating water flows through the embedded supply conduit, the inlet transition spool piece, the inlet expansion joint, and inlet condenser water box prior to entering the condenser tubes. Similarly, upon exiting the tubes, the circulating water passes through the outlet waterbox, expansion joint, transition spool piece, and embedded discharge conduit prior to being discharged to the ocean. The transition spool pieces, expansion joints, and condenser (including waterboxes) are located in the turbine building. The discharge gates are located in the embedded discharge conduit in the yard.

The design pressure of the rubber expansion joints on the inlet and outlet of the condenser (located at an elevation of 85 feet) is 81 feet.

Thus, if a circulating water pump were to pump against closed discharge gates, the pressure on the expansion joint (the pump discharge head minus the static elevation head) would be less than the design pressure. The design pressure of the transition inlet and outlet spool pieces (located at an elevation of 81 feet) is 58 feet. Similarly, the design pressure of the condenser water boxes (located at an elevation of 85 feet) is 58 feet. To prevent operating the circulating water pump and system in a configuration that could result in overpressurizing the transition spool pieces and waterboxes, mechanical stops on the condenser discharge gate operators and structural stops on the gate guide tracks inhibit the complete closing of the discharge gates. Dynamic water hammer pressures will not occur due to inadvertent closing of the water gates because the motor operators close the gates at a rate of only 15 inches per minute. These measures make circulating water system overpressurization a highly improbable event.

Inlet spool pieces and water boxes are constructed of ductile carbon steel with a corrosion-resistant internal coating, and their catastrophic failure, such that significant seawater could flood the turbine building, is not a credible assumption. The cast iron outlet spool piece was hydrotested to 1.5 times the maximum attainable circulating water system pressure.

A flooding analysis was performed based on the failure of an operator to properly secure a condenser waterbox manway cover. In order to obtain a conservative flooding rate for this scenario, waterbox manhole cover failure was assumed to be coincident with an operating error in which both circulating water pumps were running and both discharge gates were closed to the stops. In this event, approximately 43,000 gpm or 5,700 cfm of water could be expected to flow from a lower inlet waterbox manhole (the manholes with the greatest incident head of water). This flow would fill the sump and equipment pit storage areas below elevation 85 feet in 15 minutes, if the building drains are assumed to be functioning, and in 10 minutes, if the drains are not functioning. During this time, alarms would be given for turbine building sump high level and for water in the condenser pit. It may be assumed that the condensate pumps, being flooded, would have tripped, giving dramatic indication of an irregular condition.

In order to provide additional time for operators to react to this flooding casualty, a fire door was installed between the main condensers and the corridor to the emergency diesel generator rooms in order to minimize the amount of water that could enter the compartments. The door is locked closed and monitored through the security system. This door will allow at least 12 more minutes (assuming no flow of water from the building) for the postulated manhole failure flow after sumps and pits are flooded.

Subsequent to the fire door installation, a float switch system was mounted on the walls of the condenser pit. This instrumentation system eliminated the need for operator action in order to protect PG&E Design Class I equipment from any type of circulating water system leakage. The system will automatically trip the circulating water pumps if water fills the condenser pit thereby assuring that the turbine building cannot be flooded by a circulating water system leak. The system employs two-out-of-three logic for a high degree of reliability and it provides a high condenser pit level alarm indication in the control room.

10.4.5.4 Tests and Inspections

Tests and inspections of the circulating water system are done in accordance with plant procedures.

10.4.5.5 Instrumentation Applications

Instrumentation is provided to monitor and control circulating water system operation. As described in Section 10.4.5.3.1(1), high water level in the turbine building condenser pit will trip the circulating water pumps and provide an alarm in the control room.

10.4.6 CONDENSATE POLISHING SYSTEM

The PG&E Design Class II condensate polishing system removes both dissolved and suspended corrosion products and impurities from the condensate. The system is important to maintaining secondary water chemistry and minimizes the buildup of sludge in the SGs.

10.4.6.1 Design Bases

10.4.6.1.1 General Design Criterion 3, 1971 – Fire Protection

The condensate polishing system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.6.1.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the SG tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The condensate polishing system functions to contribute to the secondary chemistry control.

10.4.6.1.3 Condensate Polishing System Safety Function Requirement

(1) Protection from Flooding Effects

The flooding effects from a condensate polishing system pipe rupture do not prevent essential equipment from safely shutting down and maintaining shutdown conditions of the reactor.

10.4.6.2 System Description

The condensate polishing system is comprised of seven mixed bed demineralizers. Either six or seven demineralizers are in service processing the full condensate flow (approximately 21,000 gpm) depending on whether any one of the demineralizers is in the regeneration mode or not. The demineralizer in the regeneration mode is taken out of service and is regenerated externally in order to minimize the possibility of introducing regenerant chemicals in the condensate and feedwater system. The external regeneration process for one demineralizer normally takes about 12 to 16 hours.

Components of the condensate polishing system, including demineralizers, regenerators, and associated equipment, are located in the turbine building buttresses. The system is capable of either automatic or manual operation, and can be bypassed if necessary.

The vessels are designed to ASME BPVC Section VIII. The system piping is designed to ANSI B31.1 (refer to Section 3.2).

The condensate polishing system is classified as PG&E Design Class II. Although located within the PG&E Design Class I turbine building buttresses, the system and component supports, including enclosures, do not compromise the PG&E Design Class I seismic requirement of the turbine building buttress structure.

Personnel safety provisions include smoke detectors and portable fire extinguishers in compartments where potential for fire exists. Eyewashes and a safety shower are also provided in the chemical storage and chemical feed pump areas.

10.4.6.3 Safety Evaluation

10.4.6.3.1 General Design Criterion 3, 1971 – Fire Protection

The chemicals of the condensate polishing system (sodium hydroxide and sulfuric acid) are stored in accordance with Chapter 3 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.6.3.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The condensate polishing system is designed to polish the full condensate flow during startup and normal plant operation. During startup, the system allows recirculation of condensate at approximately 5500 gpm through the condensate polishing demineralizers and feedwater heaters, returning it to the main condenser. This design provision allows a more complete cleanup of secondary water prior to system startup.

The condensate polishing system monitors the secondary chemistry to protect the SG tubes which are a part of the reactor coolant pressure boundary from degradation during the course of its lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

10.4.6.3.3 Condensate Polishing System Safety Function Requirement

(1) Protection from Flooding Effects

The failure of condensate polishing system piping is evaluated for the effects of flooding on PG&E Design Class I essential safe shutdown equipment located in the turbine buttress building. The provisions taken to provide protection for the safe shutdown equipment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

10.4.6.4 Tests and Inspections

Tests and inspections of the condensate polishing system are done in accordance with plant procedures.

10.4.6.5 Instrumentation Applications

Instrumentation is provided to monitor and control the condensate polishing system operation.

10.4.7 CONDENSATE AND FEEDWATER SYSTEMS

The condensate and main feedwater systems, shown in Figures 3.2-2 and 3.2-3, receive condensate from the main condenser hotwells and deliver it as feedwater to the

SG at the required pressure and temperature. In the SG, the feedwater removes heat from the reactor coolant and is converted into steam.

The PG&E Design Class I portion of the main feedwater system extends from the upstream side of the main feedwater check valves to the SG nozzles. Additionally the main feedwater regulating valves (MFRVs) that are located upstream of the main feedwater check valves, along with their respective MFRV bypass valves, are PG&E Design Class I and are located in PG&E Design Class II piping that has been seismically qualified. Refer to Table 3.2-3 for a listing of PG&E Design Class II equipment that is included in the condensate and main feedwater systems.

The AFW system connects to the main feedwater lines outside of containment between the motor-operated main feedwater isolation valves (MFIVs) and the containment penetrations. This interface provides a PG&E Design Class I flow path for the AFW system to feed the SGs.

The main feedwater ring and SG tubes are further discussed in Section 5.5.2.

10.4.7.1 Design Bases

10.4.7.1.1 General Design Criterion 2, 1967 – Performance Standards

Certain portions of the main feedwater system are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, or other local site effects. The effects of a tornado on the main feedwater system are addressed to ensure that plant safe shutdown can be achieved.

10.4.7.1.2 General Design Criterion 3, 1971 – Fire Protection

The condensate and main feedwater systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.7.1.3 General Design Criterion 11, 1967 – Control Room

The condensate and main feedwater systems are designed or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other cause.

10.4.7.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the condensate and main feedwater systems variables within prescribed operating ranges.

10.4.7.1.5 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The SG level transmitters provide for sensing accident conditions and initiating the operation of necessary engineered safety features.

10.4.7.1.6 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main feedwater system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

10.4.7.1.7 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the main feedwater system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.4.7.1.8 General Design Criterion 49, 1967 – Containment Design Basis

The PG&E Design Class I portion of the main feedwater system is designed to support the capability of the containment structure to accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

10.4.7.1.9 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The PG&E Design Class I portion of the main feedwater system that penetrates containment is provided with leak detection, isolation, redundancy, reliability and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.7.1.10 General Design Criterion 57, 1971 – Closed System Isolation Valves

The PG&E Design Class I portion of the main feedwater system is designed to provide isolation valves outside the containment capable of automatic and manual closure.

10.4.7.1.11 Condensate and Feedwater Systems Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I non-ESF portion of the main feedwater system is designed to be protected against the effects of missiles that may result from equipment failures and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF portion of the main feedwater system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The PG&E Design Class I portions of the main feedwater system located outside containment are designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I portion of the main feedwater system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Protection from Flooding Effects – Outside Containment

Rupture of the PG&E Design Class II portion of the condensate and main feedwater systems would not impact PG&E Design Class I SSCs.

The PG&E Design Class I portions of the main feedwater system located outside containment are designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(6) Main Feedwater Isolation

The main feedwater system is capable of isolating main feedwater flow to the SGs to prevent overfilling the SGs or over-cooling the RCS, and to minimize mass and energy release following a secondary system pipe rupture.

10.4.7.1.12 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Main feedwater system components that require EQ are qualified to the requirements of 10 CFR 50.49.

10.4.7.1.13 10 CFR 50.55a(f) – Inservice Testing Requirements

The main feedwater system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.4.7.1.14 10 CFR 50.55a(g) – Inservice Inspection Requirements

The main feedwater system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.4.7.1.15 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The SG level transmitters provide signals to initiate AMSAC following an ATWS transient.

10.4.7.1.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main feedwater system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.4.7.1.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

PG&E Design Class I motor-operated valves (MOVs) in the main feedwater system meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

10.4.7.1.18 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the condensate and main feedwater systems.

10.4.7.1.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The main feedwater system provides instrumentation to monitor system variables during and following an accident.

10.4.7.1.20 Branch Technical Position ASB 10-2, March 1978 – Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs

The main feedwater system is designed to eliminate or reduce possible water hammer in the system, as follows:

1) The main feedwater system is designed to prevent or delay water draining from the feedring following a drop in SG level.

2) The main feedwater system is designed to minimize the volume of feedwater piping external to the SG that could pocket steam by using the shortest possible (less than seven feet) horizontal run of inlet piping to the SG feedring.

3) Tests acceptable to the U.S. Nuclear Regulatory Commission (NRC) were performed to verify that unacceptable feedwater hammer would not occur using the plant operating procedures for normal and emergency restoration of SG water level following a loss of feedwater and possible draining of the feedring.

10.4.7.2 System Description

The condensate and main feedwater systems are primarily PG&E Design Class II systems except for a part of the main feedwater system that supplies heated water to the SGs. The main feedwater pumps are designed for maximum calculated load operating conditions (refer to Figures 10.1-5 and 10.1-1 for DCPP Unit 1 and Unit 2, respectively), and are capable of supplying the required main feedwater flow to the SGs under transient load reduction conditions. The condensate pumps and condensate booster pumps provide adequate suction pressure to the main feedwater pumps under load transient conditions. During a main turbine control system load drop anticipate transient or a loss of feedwater pump load reduction, the standby condensate pump / condensate booster pump set will start, the stator coil and cooling water flow for valve FCV-31 will open, and hotwell rejection valve LCV-12 will close to provide adequate suction to the feedwater pumps.

The pressure-retaining components, or compartments of components, conform to the following codes as minimum design criteria:

(1) System pressure vessels and feedwater heaters – ASME BPVC Section VIII.

(2) System valves, fittings, and piping – ANSI Code for Pressure Piping B31.1 and B31.7 where applicable. The main feedwater lines from the MFIVs to the SGs are covered by the ASME BPVC Section I.

The condensate and main feedwater systems are of the closed type, with deaeration accomplished in the main condenser. Condensate is pumped through the generator hydrogen coolers and stator coolers, the gland steam condenser, and the air ejector condensers to the suction of the condensate booster pumps, which pump the condensate though the condensate polishing system and five stages of low-pressure feedwater heaters to the main feedwater pumps. The water discharged from the main feedwater pumps flows through the single stage of high-pressure feedwater heaters into the SGs. All feedwater heaters are horizontal, one-third-size units (three in parallel), except the No. 6 heater drain cooler, which is a single, full-size, straight-tubed heat exchanger.

Three nominal half-capacity, three-stage, vertical, can-type, centrifugal, motor-driven condensate pumps are provided with separate hotwell suction lines and a common discharge manifold. Three condensate booster pumps are provided. These are nominal half-capacity, horizontal, split-case, centrifugal, motor-driven pumps with common suction and discharge manifolds. Two nominal half-capacity, high-speed, turbine-driven main feedwater pumps are provided, with common suction and discharge manifolds. All pumps are equipped with minimum flow protective devices.

Main feedwater flows to the SGs through four lines penetrating the containment, one line for each SG. An MFRV with an MFRV bypass valve, a check valve, and an MFIV are installed in each line outside the containment.

Warmup lines are provided on the discharge of the feedwater pumps to circulate heated feedwater back through an idle feedwater pump to keep it warm and ready for service.

Drains from the No. 1 and No. 2 feedwater heaters flow to the No. 2 heater drain tank, with the flashed steam from the drain tank vented to the No. 2 heater. The No. 2 heater drain pump takes suction from the No. 2 heater drain tank and discharges to the main feedwater pump suction manifold. Drains from the four lower pressure feedwater heaters cascade to the No. 6 heater drain cooler and then to the main condenser.

The condensate and main feedwater systems do not have to operate to ensure safe shutdown of the NSSS. The AFW system, described in Section 6.5, provides adequate feedwater to the SGs from the condensate storage tank (CST) in the event of a loss of main feedwater. The reactor transient and radiological consequences of a main feedwater line break are discussed in Section 15.4.2.

In the event leakage develops from one of the feedwater heaters, that heater can be isolated and repaired while the generating unit remains on line. Since the secondary side is normally not radioactive, most leakage through valve seals will not present any radiological problems. The consequences of having the secondary side of the plant radioactive due to SG leakage are discussed in Chapters 11 and 15.

The active components in the main feedwater system required to operate in the event of a design basis accident are the check valves upstream of the AFW nozzles on the main feedwater lines, the MFIVs, the MFRVs, and the MFRV bypass valves.

The main feedwater control system consists of, in addition to the MFRVs, MFRV bypass valves, and the main feedwater pump turbine governor, individual manual controls for each MFRV and MFRV bypass valve, main feedwater pump turbine startup and speed governor controls, and the digital main feedwater control system (DFWCS). The DFWCS controls SG level using SG level, main feedwater flow, and SG density-compensated steam flow measurements. The main feedwater pump is controlled by the DFWCS using main feedwater header pressure and SG pressure. The DFWCS includes signal validation algorithms that will prevent an input channel failure from causing a control system transient requiring protective action (refer to Sections 7.2.2.11.5 and 7.7.2.7).

10.4.7.3 Safety Evaluation

10.4.7.3.1 General Design Criterion 2, 1967 – Performance Standards

The containment structure, pipeway structure, and auxiliary building, which contain the PG&E Design Class I portion of the main feedwater system, are PG&E Design Class I (refer to Section 3.8 and Table 3.2-3). These structures or applicable portions thereof and exterior components are designed to withstand the effects of winds (refer to Section 3.3.1), floods and tsunamis (refer to Section 3.4), and earthquakes (refer to Section 3.7), and to protect the PG&E Design Class I portion of the main feedwater system to ensure its safety functions are maintained. The tornado resistance capability for certain PG&E main feedwater system components supports plant safe shutdown as discussed in Section 3.3.2.

The PG&E Design Class I components and associated feedwater piping has been seismically qualified.

Portions of feedwater system are located outside are partially resistant to tornadoes, however, the capability of the system to support plant safe shutdown is maintained (refer to Section 3.3.2.5.2.7).

The main feedwater system components required to perform their PG&E Design Class I functions are located at higher elevations such that they are not affected by floods and tsunamis.

10.4.7.3.2 General Design Criterion 3, 1971 – Fire Protection

The condensate and main feedwater systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.4.7.3.3 General Design Criterion 11, 1967 – Control Room

PG&E Design Class I controls and indications for the main feedwater system are provided in the control room such that the system may be operated to perform its design function. If access to the control room is lost, the MFIVs can be operated locally. Indication of SG level and pressure are available in the control room and on the HSP.

10.4.7.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls for the condensate and main feedwater systems, including the MFIVs, MFRVs, and MFRV bypass valves, along with SG level indication, are discussed in Sections 6.2.4, 7.3, 10.4.7.3.11(6), and 10.4.7.5.

10.4.7.3.5 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

A main feedwater isolation signal is initiated when 2-out-of-3 SG channels in any loop read SG levels that are at the high-high actuation setpoint.

A low-low SG level signal is provided as input to the ESFAS.

Any SI signal develops a feedwater isolation signal.

10.4.7.3.6 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main feedwater system is designed with a diverse Class 1E power supply for the MFIVs. Additionally the main feedwater system provides independent flow paths for AFW to the SGs.

Redundant main feedwater isolation is provided by the MFRVs with their respective MFRV bypass valves and the MFIVs, along with trip of the main feedwater pumps (refer to Sections 15.2.14 and 15.4.2).

The redundancy and single failure features of the SG level instrumentation are addressed in Section 7.3.3.

10.4.7.3.7 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the main feedwater system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

10.4.7.3.8 General Design Criterion 49, 1967 – Containment Design Basis

The PG&E Design Class I portion of the main feedwater piping routed into containment and the associated containment penetrations are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding containment design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

10.4.7.3.9 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

Isolation valves that are required for containment closure are periodically tested for operability and are contained in the PG&E Design Class I portion of the main feedwater system (refer to DCPP Technical Specification 3.7.3). Testing of the components required for the CIS is discussed generally in Section 6.2.4. However, note that leak testing of the MFIVs is not required under Option B of 10 CFR Part 50 Appendix J, as noted in Table 6.2-39.

10.4.7.3.10 General Design Criterion 57, 1971 – Closed System Isolation Valves

The containment penetrations for the main feedwater system are part of penetration Group C. A description of the isolation valves and piping configuration for each penetration is provided in Table 6.2-39. Group C piping conforms to the requirements of GDC 57, 1971.

10.4.7.3.11 Condensate and Feedwater Systems Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the PG&E Design Class I non-ESF portion of the main feedwater system from internal missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Section 3.5.

The main feedwater pump turbines are located to minimize the likelihood of generation of missiles that could affect the safe shutdown of either unit.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I non-ESF portion of the main feedwater system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

The rupture of a main feedwater line is one of the principal breaks considered in the analysis of dynamic effects of pipe breaks outside the containment. Additional barriers and restraints have been added, as required, to protect PG&E Design Class I SSCs from a main feedwater line rupture, or protect the feedwater line from another line rupture.

A rupture of a feedwater line within the turbine building will result in a temperature and humidity rise. Environmental effects due to high energy pipe ruptures outside the containment are more fully evaluated and discussed in Section 3.6.4.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the main feedwater system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the main feedwater system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the main feedwater system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The PG&E Design Class I portion of the main feedwater system is physically located well above ground elevation and is not susceptible to failure by flooding from other ruptured systems.

A postulated failure of the condensate or main feedwater PG&E Design Class II piping in the turbine building would result in approximately 19,800 cubic feet of the water being released to the turbine building floor, if the entire contents of the hotwell and heater drain tank were discharged. Maloperation of the condensate or main feedwater system due to a broken pipe would be detected by changes in plant variables, alarms, feedwater heater temperature transients, or pump trips due to runout overcurrent. In addition, level switches, which alarm in the control room, are installed in the turbine building sump and in the condenser pit near the diesel generators of each unit to alert the operator to the flooding condition. Spillage from most broken pipes could be detected and isolated before significant flooding occurred.

In the event that the entire contents of the hotwell and heater drain tanks are discharged to the turbine building, the operability of PG&E Design Class I equipment (diesel generators and component cooling water heat exchangers) in the building is not endangered. The volume of water that would be discharged is within the capacity of the turbine building drain system. This system includes one 18-inch drain line from the turbine building sump of each unit to the circulating water system discharge canal (refer to Figure 3.2-27). If this drain were clogged, the water flow would begin to fill the turbine building sumps and equipment pits below 85 feet (refer to Figures 1.2-16 and 1.2-20). The entire quantity of discharge water can be accommodated in the sumps. Water would not endanger the operability of the diesel generators since a fire door is installed at the entrance to the corridor to the emergency diesel generator rooms for purposes of protection from circulating water system ruptures in the turbine building (refer to Section 10.4.5.3.1). The door is locked closed and monitored through the security system. Because of their elevation above the turbine building floor, the component cooling water heat exchangers are not susceptible to flooding damage.

These provisions also protect PG&E Design Class I equipment from flooding damage caused by the failure of other PG&E Design Class II piping or components located in the turbine building.

The PG&E Design Class I equipment in the auxiliary building is not endangered by turbine building flooding. The area of the auxiliary building housing PG&E Design Class I equipment is separated from the turbine building by 70 feet of doors and passageways. If water does enter the auxiliary building, it will drain to the building pipe tunnel, which has a capacity of approximately 345,000 gallons. The auxiliary building drain system is completely separate from the turbine building system so back flow through the drain system is not possible.

(6) <u>Main Feedwater Isolation</u>

SG high-high level signal (P-14 interlock) or an SI signal closes the MFRVs, MFRV bypass valves, and MFIVs, and trips both main feedwater pumps to prevent SG overfill and excessive overcooling.

A low T_{avg} signal coincident with a reactor trip (P-4 interlock) initiates main feedwater isolation by closing the MFRVs and MFRV bypass valves in order to protect the reactor from excessive cooldown.

Main feedwater isolation minimizes the mass and energy release into containment following a MSLB event by isolating feedwater within 9 seconds (refer to Section 6.2D.4.1.3).

10.4.7.3.12 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Main feedwater system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes valves and switches and is listed on the EQ Master List.

10.4.7.3.13 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the PG&E Design Class I components of the main feedwater system are contained in the IST Program Plan and comply with the ASME BPVC.

10.4.7.3.14 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I portion of the main feedwater system piping has a periodic ISI program in accordance with ASME BPVC Section XI.

10.4.7.3.15 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The AMSAC is initiated by an AMSAC low SG water level signal, which is derived separately from the low-low SG water level signal (refer to Sections 7.6.2.3 and 7.6.3.6).

10.4.7.3.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main feedwater system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.7.3.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The PG&E Design Class I main feedwater system MOVs are included in the DCPP MOV Program, which was developed to meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

10.4.7.3.18 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures implement the DCPP FAC monitoring program requirements. Portions of the condensate and main feedwater systems are considered in the program for erosion/corrosion monitoring.

10.4.7.3.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Table 7.5-6 summarizes DCPP's compliance with Regulatory Guide 1.97, Revision 3. Main feedwater flow is a Type D variable, and SG level is both a Type A and a Type D variable. Additionally, position indication for the MFIVs is designated as a Type B variable, but is not credited for compliance with Regulatory Guide 1.97, Revision 3, Category 1 criteria.

10.4.7.3.20 Branch Technical Position ASB 10-2, March 1978 – Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs

The SGs include top-discharge spray nozzles that reduce the possibility of steam pockets being trapped in the feedwater ring (refer to Section 5.5.2).

The main feedwater system has been designed to minimize the length of horizontal feedwater piping that could be emptied when the SG water level drops below the level of the feedwater ring. This piping has been modified as shown in Figures 10.4-2 and 10.4-3 to minimize the possibility of a damaging water hammer.

Testing was performed to verify that feedwater hammer will not occur using the plant operating procedures for normal and emergency restoration of SG water level following a loss of feedwater and possible draining of the feedring.

10.4.7.4 Tests and Inspections

Tests and inspections of the condensate and main feedwater systems are done in accordance with plant procedures.

10.4.7.5 Instrumentation Applications

A main feedwater pump control system controls the speed of the turbine-driven main feedwater pumps to achieve a programmed pressure differential between the main feedwater header leaving the No. 1 feedwater heaters and the main steam common header. The programmed pressure differential varies as a function of unit load. Main feedwater header-steam-header differential pressure indication is also provided in the control room.

SG level and feedwater flow indication is also provided.

Each MFRV and MFRV bypass valve is positioned by its own digital control system (refer to Section 7.7.2.7).

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The SG blowdown system is used in conjunction with the condensate and feedwater chemical injection system and the condensate polishing system to maintain SG water chemistry within the plant-specific limits.

The SG blowdown system functions are primarily PG&E Design Class II. The only PG&E Design Class I function performed by the system is containment isolation. The portions of the system from the SG nozzles to the isolation valves outside containment that perform this function are PG&E Design Class I.

10.4.8.1 Design Bases

10.4.8.1.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I portion of the SG blowdown system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

10.4.8.1.2 General Design Criterion 3, 1971 - Fire Protection

The PG&E Design Class I portion of the SG blowdown system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.8.1.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the SG tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The SG blowdown system functions to contribute to the secondary chemistry control.

10.4.8.1.4 General Design Criterion 11, 1967 - Control Room

The PG&E Design Class I portion of the SG blowdown system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.4.8.1.5 General Design Criterion 12, 1967 - Instrumentation and Control

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the SG blowdown system variables within prescribed operating ranges.

10.4.8.1.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

The SG blowdown system provides means for monitoring the reactor coolant pressure boundary to detect leakage.

10.4.8.1.7 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The SG blowdown system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

10.4.8.1.8 General Design Criterion 21, 1967 - Single Failure Definition

The PG&E Design Class I portion of the SG blowdown system is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

10.4.8.1.9 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the SG blowdown system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.4.8.1.10 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The SG blowdown piping that penetrates containment is provided with leakage detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.8.1.11 General Design Criterion 57, 1971 - Closed System Isolation Valves

The SG blowdown system contains piping connected to containment penetrations that are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere. These penetrations are provided with one local or remote-manual valve outside the containment.

10.4.8.1.12 Steam Generator Blowdown System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I containment isolation portion of the SG blowdown system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(2) Decay Heat Removal

The SG blowdown system is designed to facilitate the removal of decay heat from the RCS.

10.4.8.1.13 10 CFR 50.49 - Environmental Qualification

SG blowdown system components that require EQ are qualified to the requirements of 10 CFR 50.49.

10.4.8.1.14 10 CFR 50.55a(f) - Inservice Testing Requirements

SG blowdown system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.4.8.1.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

SG blowdown system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.4.8.1.16 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The PG&E Design Class I portion of the SG blowdown system is isolated upon receipt of a signal from the AMSAC.

10.4.8.1.17 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the SG blowdown system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.4.8.1.18 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The SG blowdown system containment isolation valve position status is required for post-accident instrumentation.

10.4.8.1.19 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the SG blowdown system.

10.4.8.2 System Description

A piping and instrumentation schematic for the SG blowdown system is shown in Figure 3.2-4.

The SG blowdown system for each unit is composed of two processing paths. One path discharges blowdown flow via the SG blowdown tank to the circulating water discharge tunnel. The other path recycles blowdown flow to the main condenser via the blowdown treatment system and/or the blowdown treatment bypass line. The recycle path can discharge a portion of blowdown flow to the discharge tunnel. Blowdown flow for each unit can be directed to either blowdown path alone, or to both paths simultaneously. The blowdown piping is also used as the interface between the SGs and the rapid fill and drain system that was added to facilitate operation of the SGs during unit outages.

Blowdown flow in the discharge path is processed via the SG blowdown tank; approximately 35 percent of the blowdown flow flashes to steam inside the tank and is vented to the atmosphere. The remaining liquid, approximately 65 percent of the blowdown flow, is discharged by gravity to the condenser circulating water discharge.

Blowdown flow in the recycle path may be processed by the blowdown treatment system or the blowdown treatment bypass line. This treatment system reduces the temperature and pressure of the water. The treatment system may also demineralize and recycle the blowdown water to the condensate system. In the treatment system, blowdown enters a flash tank where it is reduced in pressure. Flashed water vapor is vented from the tank through a pressure control valve to either a feedwater heater to improve cycle thermal efficiency or to the main condenser. The blowdown liquid then passes through a heat exchanger where the temperature is further reduced to approximately 110°F. The liquid may then enter a prefilter and demineralizer before being recycled to the main condenser. If required, a portion of the flash tank liquid flowing out of the heat exchangers can be routed to the plant outfall via the blowdown overboard drain line to improve the secondary water chemistry.

Blowdown water first passes through a prefilter and is then directed through one of two 60 cubic foot mixed bed demineralizers. The demineralizer removes both radioactive and nonradioactive ionic impurities. The liquid is then recycled to the main condenser. The blowdown treatment bypass line routes the depressurized, undemineralized blowdown directly to the condenser.

The blowdown tank process path and the blowdown treatment portion of the recycle process path are designed to accommodate 150 gpm of blowdown water total from four SGs on a continuous basis. The blowdown tank process path also allows a total flow of 320 gpm temporarily during certain plant conditions.

The blowdown treatment bypass portion of the recycle path, including the flash tank, is designed for 1 percent of the main steaming rate at 100 percent plant load from four SGs on a continuous basis (approximately 400 gpm total).

The SG blowdown system is classified as PG&E Design Class I from the SG nozzles up to and including the isolation valves outside of the containment and PG&E Design Class II downstream of the containment isolation valves. The classification and applicable codes for the SG blowdown system are identified in Table 3.2-3.

The blowdown system's effect on plant safety is minimal, since neither the blowdown function nor the treatment function is required continuously. Either function may be interrupted temporarily to replace failed components. Neither function is required to operate following a LOCA.

Ruptured components or failed-open valves could cause unplanned blowdown of secondary steam. Since blowdown piping in this system is 6 inches or smaller, such pipe break accidents fall within the category of minor secondary system pipe breaks. Consequences of this type of accident are detailed in Sections 15.2.14 and 15.3.2. The probability of radiation leakage is small since the system is normally nonradioactive. If, however, a failure of a blowdown pipe occurs while SG leakage is also taking place, the consequences are within the limits described in Section 15.3.2 for minor secondary system pipe breaks.

All filter and demineralizer components are located in the auxiliary building, from which leakage is processed through the liquid radwaste system. An automatically controlled isolation valve provides shutoff of the blowdown discharge path to the plant outfall if significant activity is detected. In any case, the results of failure are bounded by those of the pipe break referred to above (refer to Section 10.4.8.3.7).

The evaluation of radiological and environmental effects is treated in Section 11.2.

10.4.8.3 Safety Evaluation

10.4.8.3.1 General Design Criterion 2, 1967 - Performance Standards

The containment structure and auxiliary building, which contain the SG blowdown system's PG&E Design Class I components, are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena (refer to Sections 3.8.2.1 and 3.8.2.3 for the containment and auxiliary buildings, respectively), and to protect the system SSCs to ensure their safety functions and designs are maintained.

The PG&E Design Class I portions of the SG blowdown system are designed to perform their safety functions under the effects of earthquakes.

10.4.8.3.2 General Design Criterion 3, 1971 - Fire Protection

The SG blowdown system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.4.8.3.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

Suspended and dissolved solids that are brought in by the feedwater concentrate in the SG shell-side water during plant operation. Water must be blown down using the SG blowdown system to maintain water chemistry as specified in plant procedures. Sampling and monitoring of nonradioactive solids is accomplished by continuous conductivity measurements and grab sample analysis.

The SG blowdown system protects the SG tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

10.4.8.3.4 General Design Criterion 11, 1967 - Control Room

Controls, and position indication, for the SG blowdown system containment isolation valves are provided in the control room such that the system may be manually operated to perform its safety function.

The system isolation valves can be operated manually from the main control room. These valves can also be closed by locally venting air from the valve operator solenoids if access to the control room is lost.

10.4.8.3.5 General Design Criterion 12, 1967 - Instrumentation and Control

The outboard containment isolation valves close on the containment isolation signal, Phase A. The inboard containment isolation valves close on the steam line isolation signal (refer to Table 6.2-39).

The outboard containment isolation valves also close automatically on an AFW pump start (refer to Section 6.5.2.1.2), AMSAC actuation (refer to Section 7.6.2.3), and high radioactivity in the blowdown system (refer to Sections 10.4.8.3.7 and 11.4.2.1.2).

10.4.8.3.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

SG blowdown radiation detectors are available to detect SG tube leakage as described in Section 5.2.3.23 and Table 5.2-16. The radiation monitoring system is described in Section 11.4.

10.4.8.3.7 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The SG blowdown system is continuously monitored for radioactivity. The sampling system parallels the blowdown flow from each SG. Continuous sampling and monitoring for radioactivity is accomplished with a single composite sample taken from the four SG sample lines and passed through a radiation monitor.

The criterion used for isolation of the blowdown system is based on the concentration of activity in the blowdown. When the sampling system radiation monitor detects a preset activity level, the SG blowdown isolation valves and the blowdown tank effluent valve close. The isolation system has been designed so that the blowdown tank effluent valve closes before any significant radioactive liquid reaches the effluent isolation valve. Upon detection of activity, plant personnel may process the blowdown via the blowdown treatment system as directed by Chemistry.

The radiation monitoring system is described in Section 11.4.

10.4.8.3.8 General Design Criterion 21, 1967 - Single Failure Definition

The instrumentation and control circuits for the SG blowdown system containment isolation function are redundant in the sense that a single failure cannot prevent containment isolation (refer to Section 6.2.4.4.5). The valve control circuits are supplied with separate Class 1E 125-Vdc power. The isolation valves will fail closed on a loss of air or power.

10.4.8.3.9 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the SG blowdown system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

10.4.8.3.10 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The SG blowdown system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the CIS is discussed in Section 6.2.4.

10.4.8.3.11 General Design Criterion 57, 1971 - Closed System Isolation Valves

The SG blowdown system containment penetrations comply with the requirements of GDC 57, 1971, as described in Section 6.2.4 and Table 6.2-39.

10.4.8.3.12 Steam Generator Blowdown System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the inside containment PG&E Design Class I portion of the SG blowdown system from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(2) Decay Heat Removal

The SG blowdown system facilitates the removal of decay heat from the RCS by isolating on an AFW pump start or an AMSAC actuation (refer to Sections 6.5 and 7.6.2.3, respectively) and maintaining SG inventory.

10.4.8.3.13 10 CFR 50.49 - Environmental Qualification

The SG blowdown system containment isolation valves are required to function in harsh environments under accident conditions and are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The valves are listed on the EQ Master List.

10.4.8.3.14 10 CFR 50.55a(f) - Inservice Testing Requirements

SG blowdown system components that are within the IST program are the four inboard containment blowdown isolation valves, the four outboard containment blowdown isolation valves, and the four outboard containment sample isolation valves.

The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.4.8.3.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

The SG blowdown system piping has a periodic ISI program in accordance with the ASME BPVC Section XI.

10.4.8.3.16 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The blowdown flow from the SGs is automatically isolated as a result of an AMSAC actuation (refer to Section 7.6.2.3).

10.4.8.3.17 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The SG blowdown system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.8.3.18 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The SG blowdown system's outboard containment isolation valves' indications are credited for compliance with Regulatory Guide 1.97, Revision 3. The SG blowdown tank vent does not require monitoring (refer to Table 7.5-6, Notes 56 and 59).

10.4.8.3.19 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the FAC monitoring program for the SG blowdown system.

10.4.8.4 Tests and Inspections

The SG blowdown system is operated continuously during plant operation, thereby demonstrating system operability without the special inspections or testing required for standby systems. Equipment evaluations and inspections are performed periodically on the blowdown systems.

10.4.8.5 Instrumentation Applications

Instrumentation for the SG blowdown system is discussed in Sections 10.4.8.3.4 and 10.4.8.3.5.

10.4.9 CONDENSATE AND FEEDWATER CHEMICAL INJECTION SYSTEM

Chemical feed equipment is provided for chemical additions to the discharge of the condensate polishing system, to the main feedwater pumps' suction header, and to the discharge of the AFW pumps (refer to Figure 3.2-3 for the location of the injection points). The chemicals are injected into the condensate and feedwater system to prevent corrosion in the feedwater system and the SGs. The condensate and feedwater chemical injection system has no safety function and is classified as PG&E Design Class II.

10.4.9.1 Design Bases

10.4.9.1.1 General Design Criterion 3, 1971 – Fire Protection

The condensate and feedwater chemical injection system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.9.1.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the SG tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The condensate and feedwater chemical injection system functions to contribute to the secondary chemistry control.

10.4.9.1.3 Condensate and Feedwater Chemical Injection System Safety Function Requirement

(1) Protection from Flooding Effects

Flooding effects from a condensate and feedwater chemical injection system pipe rupture do not prevent essential equipment from safely shutting down and maintaining shutdown conditions of the reactor.

10.4.9.2 System Description

The SG blowdown system protects the SG tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

Three sets of chemical feed pumps are available in each unit for the main feedwater system. The first set consists of 3 chemical feed pumps used to inject chemicals. Individual pumps are dedicated to ethanolamine and hydrazine/carbohydrazine injection, with the third pump on standby for either service. The pumps are not used under normal operating conditions.

During normal operation, a second chemical injection feed system in each unit is used to inject concentrated ethanolamine and hydrazine solutions.

The condensate hydrazine and ethanolamine feed system for each unit consists of a 250-gallon stainless steel hydrazine day tank with two chemical feed pumps, one in operation and one standby, and a 250-gallon stainless steel ethanolamine day tank with two chemical feed pumps, one in operation and one standby. Bulk 35 percent (by weight) hydrazine is stored in liquibins and is pumped by a transfer pump to the hydrazine day tank. A 6,000 gallon closed vertical pressure vessel, with a fume scrubber and two transfer pumps, stores and supplies the ethanolamine hydroxide chemical (85 percent aqueous solution of ethanolamine) for both units. The concentrated solution is pumped as needed to the ethanolamine day tank. The four chemical feed pumps output is manually controlled. The desired ethanolamine and hydrazine concentration in the condensate can be controlled manually. The water is monitored for conductivity and dissolved oxygen at the condensate pump discharge. Conductivity and dissolved oxygen, plus pH and hydrazine concentration, are also monitored at the final feedwater header before branching to the four SGs.

A third chemical feed system is available, but not normally used. It is similar to the 2nd chemical system described above, except the hydrazine day tank is 200 gallons, the ethanolamine day tank is 300 gallons, and has 4 chemical feed pumps. Condensate from the condensate pump discharge header can be used to dilute the hydrazine and ethanolamine in the respective chemical day tank.

The AFW pump chemical feed system for each unit consists of a 500 gallon stainless steel tank, a 300 gallon stainless steel tank, and five chemical feed pumps that are piped so that the fifth pump is used as a shared spare. The chemical feed rate will be manually controlled. The chemical feed pumps pump into the discharge side of the AFW pumps. An injection line runs to the discharge of each of the three AFW pumps.

The secondary boric acid system consists of two boric acid mix/feed tanks (each tank having a capacity of 1325 gallons), three 50 percent feed pumps (each pump having a capacity of 60 gallons per hour), and a screw feeder for loading the boric acid to the mix/feed tanks. Also provided are two tank mixers (mechanical agitators) for ensuring a complete and thorough mixing of the boric acid solution in the tanks. The pumping injection flow rate will be manually controlled, primarily based on the boric acid concentration in the SG blowdown.

10.4.9.3 Safety Evaluation

10.4.9.3.1 General Design Criterion 3, 1971 – Fire Protection

The chemicals of the condensate and feedwater chemical injection system (Hydrazine/Carbohydrazine, Ethanolamine and Boric Acid) are stored in accordance with the requirements of Chapter 3 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.9.3.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The condensate and feedwater chemical injection system is designed to provide the following chemical additions to the condensate and feedwater systems to reduce SG tube corrosion:

(1) Ethanolamine to the discharge line of each demineralizer in the condensate polishing system or to the condensate pumps' discharge header when the condensate polisher system is out of service, as required, to control the pH of the feedwater and SG water.

(2) Hydrazine, or a mixture of hydrazine and carbohydrazide, to the main feedwater pump suction piping to scavenge oxygen from the feedwater to a level within procedural guidelines with a residual of hydrazine at the inlet to the SGs. Because of the similarity with hydrazine and carbohydrazide being bounded, from a safety and environmental perspective, by hydrazine, the mixture will be handled as if it were hydrazine.

(3) Ethanolamine and hydrazine, or other chemicals as specified by chemistry procedures, to the AFW pumps discharge to control the chemistry in the SGs when the AFW pumps are used to supply water to SGs.

(4) Boric acid solution to the main feedwater pump suction piping to reduce denting of tubes in the SG.

(5) Other chemicals as specified by chemistry procedures.

The system provides the capability to condition the water in the SG during wet lay-up, hydrotesting, and other times when the main feedwater system is not in operation.

The condensate and feedwater chemical injection systems are designed to provide adequate amounts of conditioning chemicals to the secondary system, as required, for the prevention of corrosion in the condensate and feedwater systems and the SG tubes.

The condensate and feedwater chemical injection system protects the SG tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

10.4.9.3.3 Condensate and Feedwater Chemical Injection System Safety Function Requirement

(1) Protection from Flooding Effects

The failure of condensate and feedwater chemical injection system piping is evaluated for the effects of flooding on PG&E Design Class I essential safe shutdown equipment located in the auxiliary and turbine buildings. The provisions taken to provide protection for the safe shutdown equipment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The ethanolamine/hydrazine injection pumps and supply tanks for the condensate system are located in the turbine building west buttress and the turbine building. The concentrations in the ethanolamine and hydrazine supply tanks can be up to 85 percent and 35 percent, respectively. The tanks are vented to the outside of the building. There are no ESFs in the vicinity that would be damaged or rendered inaccessible by a ruptured supply tank.

The bulk ethanolamine storage tank, its fume scrubber, and its two transfer pumps are located in the turbine building west buttress, which houses the condensate polishers. Toppling of this vertical tank is not expected to damage the nearby PG&E Design Class I diesel fuel oil lines which are inside an adequately covered recessed pipe trench. Any accidental chemical spill, which is harmless to the steel pipes, would be confined within the trench and be prevented from reaching the diesel generator room by firestops.

The AFW pump chemical injection system supply tanks are located in the auxiliary building over a ventilation opening at the 115 foot elevation floor. The AFW pumps served are located below on the 100-foot elevation floor. A ruptured supply tank could cause 300 or 500 gallons of solution to fall partially on motor-driven AFW pump 1-3 or

2-3. The motor has a drip-proof enclosure and the centerline of the pump motor unit is 2 feet-6 inches above the 100-foot floor elevation. The area is drained by two 4 inch floor drains. The floor area in the vicinity of the AFW pumps is in excess of 1000 square feet so that 500 gallons would cause less than 1 inch of depth on the floor. Motor-driven AFW pump 1-3 or 2-3 could be impacted, due to water in the motor, by this accident; however, the second motor-driven pump and the turbine-driven pump would still be available.

The boric acid mix/feed tanks are located in the turbine building at the 85-foot elevation (ground level). The boric acid feed pumps are also located at this elevation. The floor area at this elevation (ground level) is large enough so that a ruptured feed tank would cause only a negligible depth of water on the floor, even though up to 1100 gallons of solution could be released. The only PG&E Design Class I component that could be affected by water is the diesel generator fire protection controls for Unit 1 only. These controls are wall mounted in a splash-proof box. In addition, the feed tanks are constrained to prevent any lateral movement or overturning and resist a seismic event. There are no other ESFs in the vicinity that would be damaged or rendered inaccessible by a ruptured feed tank. The feed tanks are purged with nitrogen and vented to the building.

10.4.9.4 Tests and Inspections

Tests and inspections of the condensate and feedwater chemical injection system are done in accordance with plant procedures.

10.4.9.5 Instrumentation Applications

The rate of feed of the chemical injection pumps into the main condensate and feedwater systems is proportioned to feedwater flow with manual adjustment of rate of chemical injection to rate of feedwater flow. The main condensate and feedwater supply tanks are equipped with level gauge glasses. The AFW supply tanks are equipped with low level alarm switches in addition to level gauge glasses. The chemical feed pump motors will alarm on overcurrent.

The pumping injection flow rate for the boric acid injection system will be manually controlled based on the boric acid concentration in the SG blowdown. The feed tanks are equipped with level indicators and the feed pumps include thermal overload protection.

10.4.10 REFERENCES

1. Final Environmental Statement for Diablo Canyon Power Plant, U.S. Nuclear Regulatory Commission, Washington, D.C., May 1973.

10.4.11 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 10.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
1. <u>General Design Criteria</u>												
Criterion 2, 1967	Performance Standards		X				X			X	X	
Criterion 3, 1971	Fire Protection		X				X		X	X	X	X
Criterion 4, 1967	Sharing of Systems		X									
Criterion 9, 1967	Reactor Coolant Pressure Boundary								X		X	X
Criterion 11, 1967	Control Room		X				X			X	X	
Criterion 12, 1967	Instrumentation and Control System		X				X			X	X	
Criterion 15, 1967	Engineered Safety Features Protection Systems		X							X		
Criterion 16, 1967	Monitoring Reactor Coolant Pressure Boundary										X	
Criterion 17, 1967	Monitoring Radioactivity Releases		X		X	X					X	
Criterion 21, 1967	Single Failure Definition		X							X	X	
Criterion 49, 1967	Containment Design Basis		X							X		
Criterion 54, 1971	Piping Systems Penetrating Containment		X				X			X	X	

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
1. General Design Criteria (cont'd.)												
Criterion 57, 1971	Closed System Isolation Valves		X				X			X	X	
2. System Safety Functional Requirements												
Protection from Missiles		X										
Protection from Missiles and Dynamic Effects			X				X			X	X	
Decay Heat Removal			X								X	
Main Steam Isolation			X									
Secondary Side Pressure Control			X									
Steam Flow Restriction			X									
Reactor Coolant System Cooldown							X					
Internal Flooding								X	X	X		X
Main Feedwater Isolation										X		
3. 10 CFR Part 50												
50.48(c)	10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805		X				X			X	X	

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
3. <u>10 CFR Part 50 (cont'd.)</u>												
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants		X							X	X	
50.55a(f)	Inservice Testing Requirements		X				X			X	X	
50.55a(g)	Inservice Inspection Requirements		X				X			X	X	
50.62	Requirements of Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants	X								X	X	
50.63	Loss of All Alternating Current Power		X				X					

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
4. Regulatory Guides												
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident		X							X	X	
5. NRC NUREG												
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements		X		X	X						
6. NRC Generic Letters												
Generic Letter 89-08, May 1989	Erosion/Corrosion-Induced Pipe Wall Thinning	X	X							X	X	
Generic Letter 89-10, June 1989	Safety-Related Motor-Operated Valve Testing and Surveillance									X		

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
7. <u>Branch Technical Position</u>												
Branch Technical Position ASB 10-2, March 1978	Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs									X		

TABLE 10.1-1

STEAM BYPASS AND RELIEF VALVES

Design Class[a]	Relieves to	Pressure Mode	Pressure[b]	Capacity ± 10%
Main Steam Power-operated Valves (10% Atmospheric Dump Valves):				
I	Atmosphere	Operating	790 psia	327,255 lb/hr
		Maximum	1,179 psia	495,949 lb/hr
Turbine Bypass Valves (40% Cooldown and Bypass Valves):				
II	Condenser	Operating	790 psia	527,099 lb/hr
		Maximum	1,165 psia	789,875 lb/hr
Power-operated Steam Relief Valves (35% Atmospheric Dump Valves):				
II	Atmosphere	Operating	790 psia	612,014 lb/hr
		Maximum	1,165 psia	917,123 lb/hr

Main Steam Spring-loaded Safety Valves:

Design Class	Relieves to	Set Pressure	At 3% Accumulation	Valve Full Open	Orifice Size (inches)
I	Atmosphere	1,065 psig	803,790 lb/hr	867,431 lb/hr	4.515
I	Atmosphere	1,078 psig	813,471 lb/hr	877,875 lb/hr	4.515
I	Atmosphere	1,090 psig	822,408 lb/hr	887,516 lb/hr	4.515
I	Atmosphere	1,103 psig	832,090 lb/hr	897,960 lb/hr	4.515
I	Atmosphere	1,115 psig	841,027 lb/hr	907,601 lb/hr	4.515

(a) PG&E Design Class; refer to Table 3.2-1

(b) Ref.: DCMs M-46 (U-1) and M-71 (U-2)
10% pressure values from envelopes of lines 227 and 228, which have the highest accident pressure
35% pressure values from envelope of line 590, which supplies the PORVs
40% pressure values from envelope of line 587 supplying the valves

TABLE 10.1-2

SECONDARY SYSTEM OPERATING PARAMETERS
AT 100 PERCENT RATED POWER

Mass of water in one steam generator, lb	102,600
Mass of steam in one steam generator, lb	6,900
Secondary side operating temperature, °F	522
Steam generator blowdown tank capacity, ft^3	641
Air ejector flowrate - rated, scfm	25
- expected average, scfm	2.5
Total mass of water in secondary system, lb	2,800,000
Total mass of steam in secondary system, lb	60,000

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 10.3-1

MAIN STEAM LINE VALVE PLANT STARTUP LEAKAGE TEST RESULTS

Valve Type and Leakage Path	*Quantity*	*Leakage per Valve*
Leakage to atmosphere through seat of 6-inch safety valves[(a)]	*20*	*10 bubbles/min*
Leakage to atmosphere through seat of 8-inch power-operated relief valves	*4*	*24 cc/hr*
Leakage to auxiliary feed pump turbine through seat of 4-inch isolation valves	*2*	*6 cc/hr*
Leakage to atmosphere through stems of gate valves in series with power-operated relief valves[(b)]	*4*	*12 cc/hr*
Leakage to atmosphere through stems of main steam isolation valves[(c)]	*4*	*4 cc/hr*
Leakage to atmosphere through stems of globe valves bypassing the main steam isolation valves	*4*	*negligible*

(a) Tested in accordance with API Standard 527. Test made after popping with nitrogen and then pressure reduced to 92 percent of nitrogen popping pressure.

(b) Tested seat at 1500 psig for 3 minutes. Result shown is maximum of all valves tested - hydro test.

(c) Requirement: leakage per valve shall not exceed 2 cc of water per hour when subjected to hydrostatic pressure of 1100 psig, or 0.06 scfh of air with a differential pressure of 80 psi. There are two valves per valve assembly. These are purchase specifications, not operational test requirements.

10.3-2

SUMMARY OF RESULTS UNDER PIPE RUPTURE CONDITIONS

	Check Valve	Isolation Valve
Velocity at disk impact, rad/sec	74.7	77.6
Acceleration at disk impact, rad/sec^2	6373	5474
Energy at disk impact, 10^6 in-lb	0.817	0.888
Maximum flowrate through valve, lb/sec	2767	3220

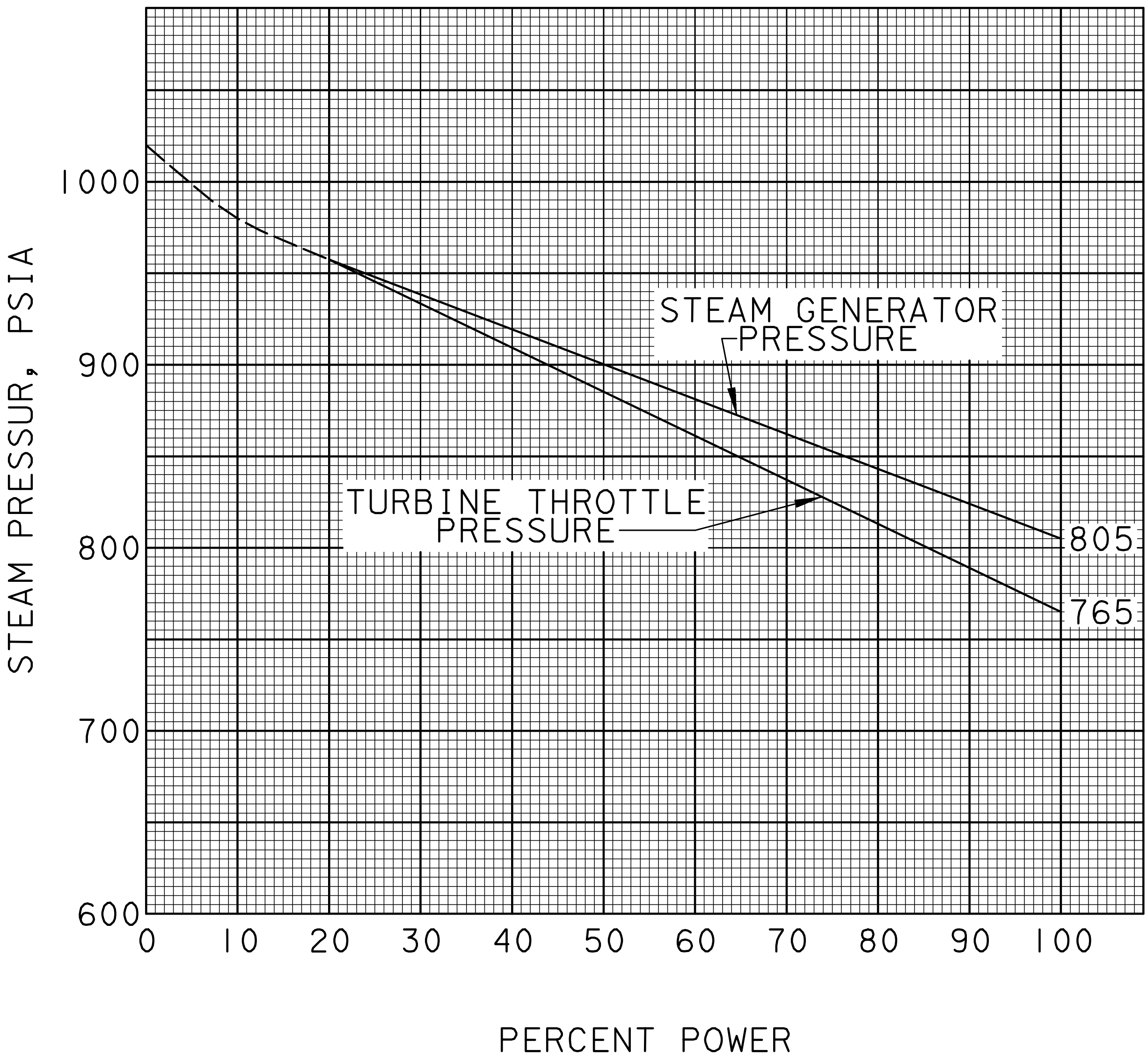
TABLE 10.4-1

MAIN CONDENSER PERFORMANCE DATA

The condenser for each unit has two shells. The data given below are based on the full load heat balance.

Characteristics	Unit 1 Shell	Unit 2 Shell
Total heat load, Btu/hr[c]	8.19×10^9	8.19×10^9
Absolute pressure in condensing zone, in. Hg (with 56.5°F circulating water temperature at inlet to condenser)	1.71	1.71
Circulating water flow, gpm[d]	862,000	862,000
Average velocity in tube, ft/sec	6.8	6.8
Effective surface area, ft^2 [e]	618,150	618,150
Cleanliness factor, % [a]	85	85
Tube outside diameter, in.	1	1
Tube BWG	22	22
Tube overall length, ft	40 ft 9 in.	40 ft 9 in.
Tube effective length, ft	40.56	40.56
Number of tubes	58,216	58,216
Total condensate stored at maximum operating level (82 ft-6 in.), cu ft	18,880[b]	18,880[b]

(a) This is the percent of clean tube heat transfer coefficient used in the design of the condenser.
(b) There is a single hotwell for each unit.
(c) The Unit 1 and Unit 2 condensers were originally rated for a nominal heat load of 7.6×10^9 Btu/hr. The post Alstom LP Turbine Retrofit heat loads based upon the Alstom supplied “Full Load” heat balance diagrams for Unit 1 and Unit 2 are bounded by the Westinghouse approximated value shown in the table. Refer to Figures 10.1-6 and 10.1-2 for the full load heat balances, Unit 1 and Unit 2, respectively.
(d) This is a nominal value based on pump design documents and impacts on flow due to varying tidal conditions.
(e) Vendor supplied value. It is considered a nominal value.



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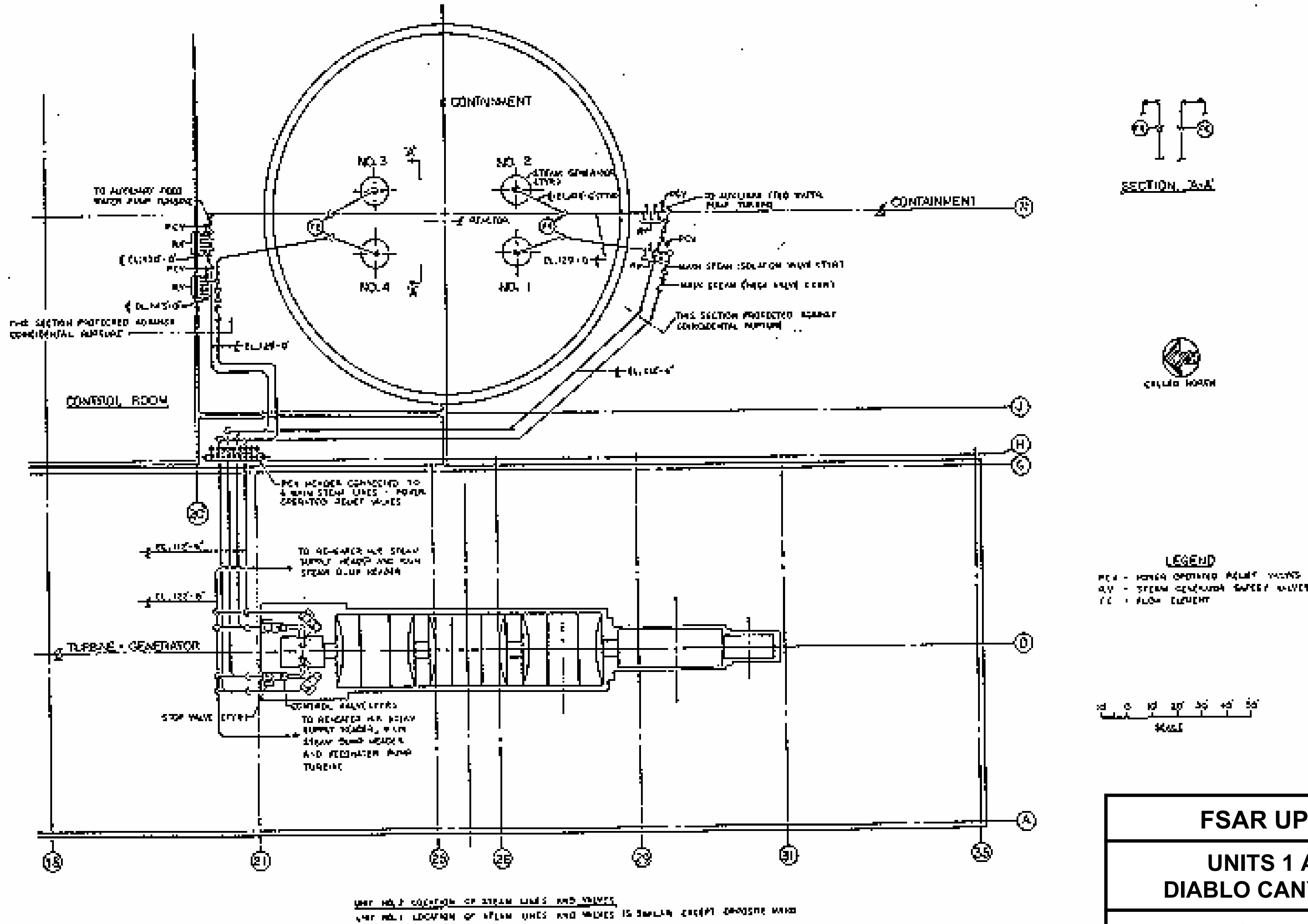
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 10.2-1 **STEAM GENERATOR CHARACTERISTIC PRESSURE CURVES**



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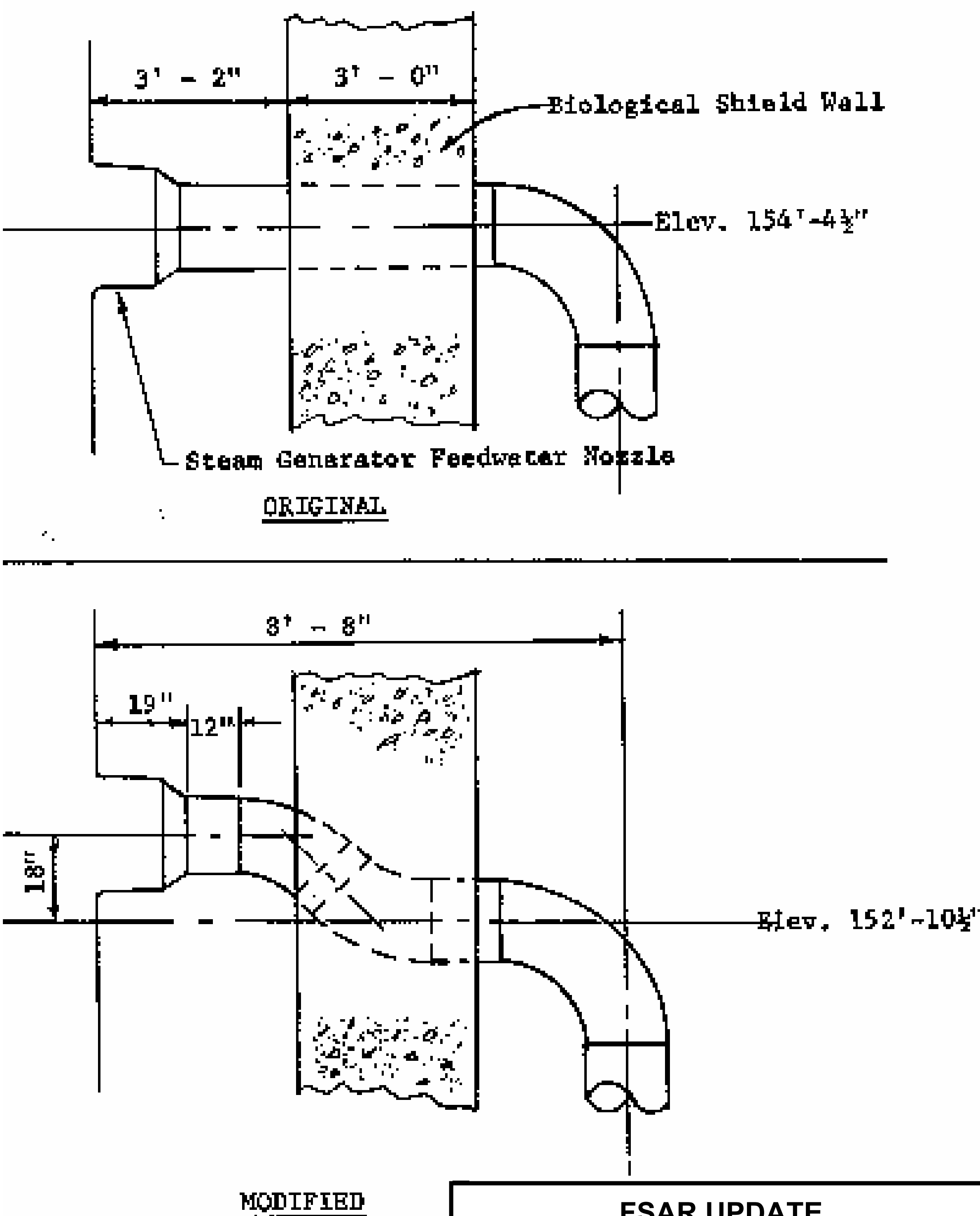
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 10.3-6
LOCATION OF STEAM LINES AND VALVES

Revision 11 November 1996

STEAM GENERATORS 1 and 4



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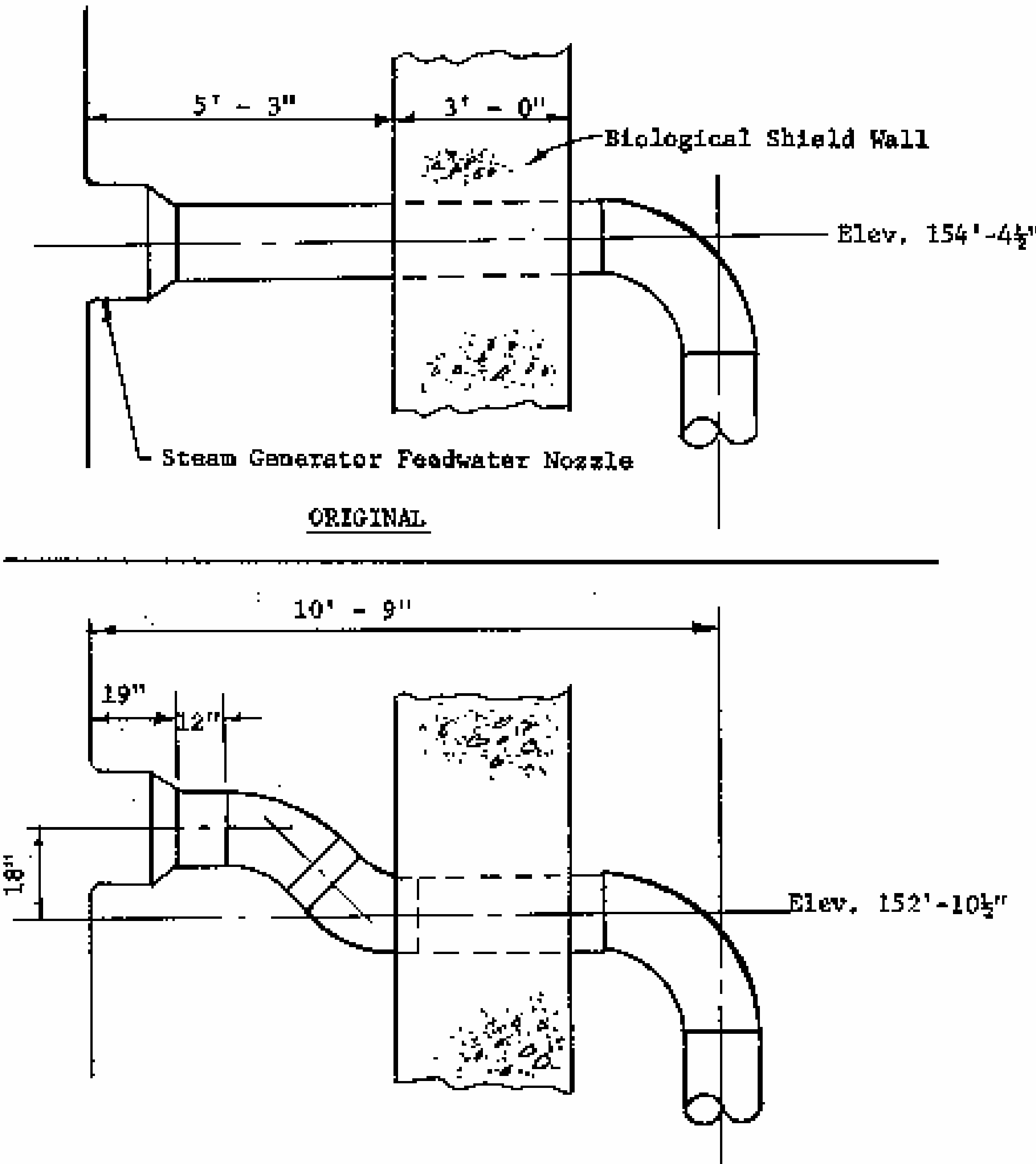
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 10.4-2 REVISION OF STEAM GENERATOR FEEDWATER PIPING STEAM GENERATORS 2 AND 3

STEAM GENERATORS 2 and 3



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**UNITS 1 AND 2
DIABLO CANYON SITE**

**FIGURE 10.4-3
REVISION OF STEAM GENERATOR
FEEDWATER PIPING
STEAM GENERATORS 2 AND 3**