Millstone Power Station Unit 3
Safety Analysis Report

Chapter 10

CHAPTER 10 - STEAM AND POWER CONVERSION SYSTEM

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This chapter provides information concerning the Millstone 3 steam and power conversion system.

10.1 SUMMARY DESCRIPTION

The steam and power conversion system (Figure 10.1-1) is designed to accept steam from a pressurized water-type nuclear steam supply system (NSSS) at a steam generator power of 3,666 MWt. The system consists of an 1,800 rpm tandem compound, 6-flow, 43 inch last stage bucket turbine coupled to a single, hydrogen inner-cooled generator and rotating rectifier exciter. This system converts the thermal energy of the steam to electric energy, producing 1,296 MWe (design rated) at the NSSS warranted condition (Figure 10.1-2).

The steam and power conversion system is based on a turbine cycle consisting of motor-driven condensate pumps, turbine-driven feedwater pumps, six stages of feedwater heating, and a single stage of steam reheat. Moisture separation and steam reheat are provided between the high and low pressure turbines. Steam is condensed in three surface-type, single-pass condensers of divided water box design, and condensate is collected in the hotwell which has storage capacity equivalent to approximately 5 minutes of full load operation.

The condensate and feedwater system returns feedwater to the steam generators through six stages of extraction heating arranged in three parallel strings.

The system provides load following capability in accordance with the NSSS vendor's specified capability and within the turbine manufacturer's recommended limitations. Turbine bypass and atmospheric steam dump capacity accommodates more severe load rejections without reactor or turbine trip, as specified by the NSSS vendor.

The principal design and performance characteristics of the steam and power conversion system are summarized in Table 10.1-1. Those design features of the steam and power conversion system that are safety-related QA Category I are indicated by asterisks.

TABLE 10.1–1 STEAM AND POWER CONVERSION SYSTEM PRINCIPLE DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics
Turbine-Generator (Section 10.2)	
Turbine	1,235,219 kW (design rated),
	1,800 rpm tandem compound, 6-flow, 43 inch last stage bucket, single stage reheat.
Generator	1,354,700 kVa, 1,800 rpm, direct coupled, 3 phase, 60 Hz, 24,000V, liquid cooled stator hydrogen cooled rotor rated at 0.925 pf, 0.50 short circuit ratio (SCR) at 75 psig hydrogen pressure.
Exciter	3.080 kW, 520V, 0.5 response ratio, Alterrex design (silicon-diode rectifier).
Control	Electrohydraulic control (EHC).
Overspeed Protection	Redundant speed control systems:
	1. Normal and transient EHC speed control system.
	2. Mechanical overspeed system.
	3. Electrical backup overspeed system.
Moisture-Separator/ Reheaters	ASME VIII
Turbine Gland Seal System (Section 10.4.3	Operated with main steam, extraction steam or auxiliary steam. Noncondensables discharged to atmosphere.
Main Steam Supply System (Section 10.3)	
Main Steam Piping	* From each steam generator up to the first rupture restraint immediately downstream of the main steam isolation trip valves: ASME III, Code Class 2.
	* From main steam isolation trip valve rupture restraint to the east wall of the turbine building: ASME III, Code Class 3.
	* Main steam to auxiliary feedwater pump turbines: from main steam lines in containment up to and including containment isolation vales: ASME III, Code Class 2. From containment isolation valves to inlet and exhaust of auxiliary feedwater pump turbine: ASME III, Code Class 3.
	* Balance of the main steam piping: ANSI B31.1.0b-1971.

TABLE 10.1–1 STEAM AND POWER CONVERSION SYSTEM PRINCIPLE DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics
Main Steam Isolation Trip Valves	* ASME III, Code Class 2; maximum closing time 10 sec.
Main Steam Safety Valves	* ASME III, Code Class 2; flow capacity equal to 105 percent of the maximum calculated steam generators mass flow at setpoint pressure plus accumulation. Flow from any one valve does not exceed 970,000 lb/hr at 1,200 psia.
Main Steam Pressure Relieving Control Valves	* ASME III, Code Class 2; flow capacity equal to 15 percent of the maximum calculated steam generators mass flow at no load pressure. Flow from any one valve does not exceed 970,000 lb/hr at 1,200 psia.
Turbine Bypass System (Section 10.4.4)	For the range of NSSS design parameters, a rapid ramp load decrease equivalent to 50 percent of rated thermal power / turbine load at a maximum turbine unloading rate of 200 percent per minute can be accommodated without a reactor or turbine trip, and without lifting the main steam safety valves. Piping: ANSI B31.1-Ob-1971.
Turbine Bypass Valves	Capable of completely opening from closed position to full open position within 3 seconds after receipt of a trip open signal (normal modulation from full close to full open in 20 seconds). The capacity of any one turbine bypass valve will not exceed 970,000 lb/hr at 1,200 psia.
Main Condensers (Section 10.4.1)	Triple shell, approximately 503,000 sq ft surface area, 18°F design tube rise, equalized steam dome and hotwell sections.
Condenser Air Removal System (Section 10.4.2)	Two condenser air removal pumps for initial shell side air removal, two steam jet air ejector units for maintaining vacuum: noncondensible gases from air ejectors discharged to radioactive gaseous waste systems (Section 11.3).
Circulating Water and Associated Systems (Section 10.4.5)	Six motor driven wet pit vertical water pumps, normally controlled by six Variable Frequency Drives (VFDs), 912,000 gpm total flow, discharge through concrete tunnel to seal pit.

TABLE 10.1–1 STEAM AND POWER CONVERSION SYSTEM PRINCIPLE DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics
Steam Generator Blowdown System (Section 10.4.8)	The normal steam generator blowdown system flow is 22,800 lb/hr, per steam generator. Blowdown liquid flashed into the steam generator blowdown flash tank. Flashed steam is discharged to fourth point extraction and liquid drained to the condenser. There is continuous sampling for chemical and radioactive content (Section 9.3.2.2).
	* All piping and valves inside the containment structure up to and including the first rupture restraint outside the containment structure ASME Section III, Code Class 2.
	All other piping: ANSI B31.1.Ob-1971.
Condensate and Feedwater Systems (Section 10.4.7)	Three one-half capacity motor-driven condensate pumps, six stages of regenerative feedwater heating, two one-half capacity turbine-driven steam generator feedwater pumps, one one-half capacity motor-driven steam generator feedwater pump.
	* Piping from the rupture restraint upstream of the containment isolation valve outside the containment structure to steam generator inlets: ASME III, Code Class 2.
	* Piping from main steam valve building wall up to containment isolation valve rupture restraint: ASME III, Code Class 3.
	Piping from hotwell up to main steam valve building wall: ANSI B31.1.Ob-1971.
Feedwater Isolation Trip valves	* ASME III, Code Class 2, maximum closing time 5 seconds.
Auxiliary Feedwater System (Section 10.4.9)	* Two motor-driven steam generator auxiliary feedwater pumps: ASME III, Code Class 3; one turbine-driven steam generator auxiliary feedwater pump, ASME III, Code Class 3; one 360,000 gallon capacity demineralized water storage tank (DWST), ASME III, Code Class 3; one DWST heater non-nuclear safety; one DWST heater circulating pump, non-nuclear safety.
	* All piping up to but excluding the auxiliary feedwater containment isolation valve and pipe to the feedwater system pipe connection: ASME III, Code Class 3.
	* Piping from and including the auxiliary feedwater containment isolation valve to the feedwater system pipe connection: ASME III, Code Class 2.

TABLE 10.1–1 STEAM AND POWER CONVERSION SYSTEM PRINCIPLE DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics
Condensate Demineralizer	Full flow condensate demineralizer, 9,857,455 lb/hr capacity; eight mixed bed demineralizers: ASME VIII, Div 1 piping ANSI
Mixed Bed System (Section 10.4.6)	B31.1.Ob-1971.

FIGURE 10.1-2 RATED HEAT BALANCE

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

10.2 TURBINE-GENERATOR

The turbine-generator receives steam from the main steam supply system (Section 10.3) and transforms the thermal energy in the steam to electrical energy. The turbine-generator and associated accessories are supplied by the General Electric Company. The turbine steam system is shown on the station fundamental diagram (Figure 10.1-1).

10.2.1 DESIGN BASES

The turbine-generator and the turbine steam system are designed in accordance with the following criteria:

1. The turbine is designed for normal operation based on steam conditions reflecting steam generator outlet conditions (Figure 10.1-2).

2. The turbine-generator is designed for base load operation with remote dispatching provisions.

3. The turbine-generator allows safe continuous operation at the maximum capability of the turbine (valves wide open (VWO) condition).

4. The turbine-generator and associated steam and power conversion systems are capable of a 50 percent load rejection without producing a reactor trip by dumping steam into the condenser through the turbine bypass system (40 percent) (Section 10.4.4) plus NSSS transient capability (10 percent).

5. The turbine-generator is capable of increasing or decreasing electrical load at a rate consistent with the requirements of the NSSS and the turbine manufacturer loading rate recommendations. However, under emergency conditions the turbine-generator can accept greater load changes.

6. The turbine-generator is built in accordance with the turbine manufacturer's standards and the industry codes that most closely approximate the conditions of turbine-generator applications.

7. The moisture separator/reheaters are designed and fabricated in accordance with Section VIII, Division 1, of the 1971 ASME Boiler and Pressure Vessel Code.

8. Generator rating, temperature rise, and insulation class are in accordance with applicable ANSI Standards.

9. Preoperational and startup testing of the power conversion system meet the requirements of Regulatory Guide 1.68.

10.2.2 DESCRIPTION

The description of the turbine generator includes the turbine-generator equipment, moisture separation, use of extraction steam for feedwater heating, and control functions that could influence operation of the reactor coolant system. The turbine overspeed system is described in detail. The control, lubrication, and support systems for the turbine-generator are shown on Figures 10.2-1, 10.2-2, and 10.2-3.

10.2.2.1 Turbine-Generator Equipment

The turbine is an 1,800 rpm, tandem compound, 6-flow, steam reheat machine with 43-inch last-stage blades. The turbine consists of one double-flow high pressure cylinder and three double-flow low pressure cylinders. Steam from the main steam system, flowing through four main steam lines, passes through the turbine stop and control valves in each line and into the high pressure turbine. Steam leaving the high pressure turbine passes through the moisture separator and reheater to the inlets of the low pressure turbines. Each of the lines between the reheater outlets and low pressure turbine inlets is provided with a combined intercept and stop valve.

The moisture separator/reheaters are located on the operating floor on both sides of the turbine. Each moisture separator/reheater has one stage of reheat. High pressure turbine exhaust steam passes through the chevron baffles which remove the moisture and then passes through the reheater bundle which uses main steam as the reheating medium. The moisture separators are provided with relief valves which discharge to the condenser. The relief valves are mounted on the hot reheat lines to the low pressure turbines.

The exhaust from the three low pressure turbines passes to the condenser where it is condensed by the circulating water system (Section 10.4.5).

Turbine extraction steam, used for six stages of feedwater heating and two half-capacity steam generator feedwater pump turbines, is taken from seven extraction points (Figure 10.1-1): one on the high pressure turbine casing, one from the exhaust of the high pressure turbine, one from the hot reheat piping, and four from the low pressure turbine casing. Motor-operated block valves and power assisted nonreturn valves in the first, second, third, and fourth point heater extraction piping and antiflash back baffles in the fifth point heaters protect against the possibility of turbine water induction or overspeed due to energy stored in the extraction steam system.

The extraction steam valves are not safety related. As such, they are not inspected or tested within the plant's inservice inspection program (ASME Section XI). However, these valves are operationally tested monthly to ensure proper operation.

The extraction line non-return valves are straight-through type having a swinging disc rotating on a shaft in bushed bearings. To ensure positive closing in the event the turbine is tripped due to overspeed, a spring loaded air cylinder, which is installed on the outside of the valve body, is connected by means of a piston rod and shaft linkage. The disc arm and shaft are free to swing without movement of the connecting linkage to the air cylinder.

Under normal operating conditions with the air cylinder pressurized, the piston is in its top position with the closing spring compressed. The valve design is such that with the air cylinder pressurized, the valve disc is free to swing open or closed as with any ordinary check valve.

Upon release of air pressure, the closing spring acts through the linkage to hold the disc to its seat. The valve will remain in this position until air pressure is re-established, moving the piston upward.

The air cylinder has a connection for a high pressure air supply below the piston and a leakoff connection above the piston, connected to a manually operated test valve, which permits testing to verify that the non-return valve piston rod is free to move.

Generator

The generator is sized to accept the output of the turbine. The generator is equipped with an excitation system, hydrogen control system, a seal oil system, and a cooling water system for the stator. The generator terminals are connected through the isolated phase generator leads and generator circuit breaker (GCB) to the main stepup transformers and normal service transformers.

The generator excitation system provides a DC source for the field and controls the voltage of the generator. The hydrogen control system includes pressure regulators, control for the hydrogen gas, and a circuit to supply and control carbon dioxide used during filling and purging operations. A hydrogen seal oil system prevents hydrogen leakage through the generator shaft seals. This system includes pumps, controls, and a storage tank, and degasifies the oil before it is returned to the shaft seals. The cooling water system for the stator provides cooling for the stator windings.

Turbine Control System

The turbine control system is capable of remote manual or automatic control of acceleration and loading of the unit at preset rates, and holding speed and load at a preset level. The system contains valve positioning, operating, and tripping devices with provisions for testing valve operation including local manual trip capability.

The turbine control system is an electrohydraulic control (EHC) system and includes both digital and analog circuitry, electronic servo hardware, and hydraulic valve actuators. During automatic operation, the EHC system speed and load control units send output signals to the servo system to position the valve actuators, which, in turn, admit steam to the turbine and thus control turbine speed and/or load. A standby manual control system is provided independent of the speed and load control units and may be used to maintain power output while subsystems are being repaired, without bypassing turbine protection and trip systems.

On rapid loss of load, the turbine control system will reduce main steam flow through the turbine faster than steam generation can be reduced. If the load loss is less than 50 percent of rated load, the turbine bypass system will operate to allow reduction of reactor power without trip. The reactor and turbine controls are interconnected so that a reactor trip signal will trip the turbine to

prevent an overly rapid cooldown of the reactor. A turbine trip signal will also trip the reactor. The turbine will trip under the following conditions:

1. Turbine overspeed
2. Low turbine bearing oil pressure
3. High steam generator water level
4. Safety injection signal
5. Generator trip
6. Excessive thrust bearing wear
7. Low hydraulic fluid supply pressure
8. Low condenser vacuum
9. Main shaft oil pump low discharge pressure (when turbine speed is greater than 1,350 rpm)
10. High moisture separator water level
11. Loss of both primary and backup speed feedback signals (when the EHC speed control is in automatic mode)
12. High exhaust hood temperature
13. Loss of stator coolant
14. Loss of EHC 125 VDC power supply below 1350 rpm
15. Low emergency trip system fluid pressure
16. Action of the mechanical trip handle or main board pushbutton
17. Reactor trip

10.2.2.2 Turbine Overspeed Protection

The EHC provides a normal overspeed protection system and an emergency overspeed protection system to limit turbine overspeed. These two systems are essentially separate and independent. The normal overspeed protection system is part of the turbine load and speed control system and is designed to limit turbine overspeed without a turbine trip under all load conditions. The emergency overspeed protection system is part of the emergency trip system and is designed to

trip the turbine if the turbine speed exceeds 110 percent of rated speed. All components of the overspeed protection systems can be tested while the turbine is carrying load.

The turbine control system (Figures 10.2-1 and 10.3-1) provides two independent valve groups for protection against overspeed in each steam admission line to the turbine. Steam is admitted to the high pressure turbine through four main stop valves, a manifold (equalizer line), four main control valves, then four unmanifolded main steam inlets. Steam leaving the high pressure turbine passes through the moisture separator reheaters and the combined intermediate valves prior to entering the low pressure turbine. Each combined intermediate valve contains two independently operated valve discs in series, one called an intercept valve and the other called an intermediate stop valve.

Valve closing actuation of the turbine stop, control, and intermediate valves is provided by springs and aided by steam forces upon the reduction of relief of hydraulic fluid pressure. The valves are designed to close in approximately 0.2 seconds. The system is designed so that loss of hydraulic fluid pressure for any reason leads to valve closing (fail safe).

A single failure of any component will not lead to destructive overspeed. A multiple failure, including combinations of undetected electronic faults and/or mechanically stuck valves and/or hydraulic fluid contamination at the instant of load loss would be required to reach destructive overspeed. The probability of such joint occurrences is extremely low, due to the high design reliability of components and frequent inservice testing.

The extraction steam lines (Figure 10.4-3) to the first through fourth point feedwater heaters contain extraction steam line nonreturn valves which are used to protect the turbine from reverse flow of vapor in the event of a sudden turbine trip or load reduction. The valves are a swinging disc design with a spring assisted closure mechanism to ensure rapid closure in the event of a reversal of steam flow direction past the valve. This results in an extremely conservative design since the turbine manufacturer has determined that the failure of extraction steam nonreturn valves during a loss of maximum load would only cause a moderate rise in speed. This is a result of the modest steam pressure levels and entrained steam volumes in the extraction steam lines of turbines for light water reactors in relation to the very large rotor inertia relative to the turbine power of an 1800 rpm unit. This is also the reason that extraction steam line nonreturn valves are not required on the extraction lines to the fifth and sixth point heaters.

Further, an analysis has been performed (Section 3.5.1.3) which has determined an acceptable value of damage probability to safety related equipment as a result of ductile fracture of a rotating turbine component upon turbine runaway after extensive, highly improbable turbine control system failure. Section 10.2.3.6 discusses the testing of steam valves.

10.2.3 TURBINE INTEGRITY

This section provides information to demonstrate the integrity of turbine rotors.

10.2.3.1 Materials Selection

Turbine rotors are made from vacuum melted or vacuum degassed Ni Cr Mo V alloy steel by processes which minimize flaw occurrence and provide adequate fracture toughness. Tramp elements have been controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials (Section 10.2.3.1) to produce a balance of adequate material strength and toughness to ensure safety while providing simultaneously high reliability, availability, efficiency, etc., during operation.

Turbine operating procedures are employed to preclude brittle fracture at startup by ensuring that the metal temperature of wheels and rotors (a) is adequately above the FATT and (b) as defined above is sufficient to maintain the fracture toughness to tangential stress ratio at or above 2 inches (Spencer and Timo 1974).

10.2.3.3 High Temperature Properties

Temperatures in the high pressure turbine are below the creep rupture range. Creep rupture is, therefore, not considered to be a significant factor in assuring rotor integrity over the lifetime of the turbine. Basic data is obtained from laboratory creep rupture tests.

10.2.3.4 Turbine Design

The turbine assembly is designed to withstand normal conditions and anticipated transients, including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

1. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

2. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20 percent overspeed is controlled in the design and operation so as to cause no distress to the unit during operation.

10.2.3.5 Preservice Inspection

The preservice inspection program included:

1. As part of the manufacturing process, the rotors were subjected to ultrasonic examinations.

2. All finish-machined surfaces were subjected to a magnetic particle examination.

3. Each fully bucketed turbine rotor assembly was spin tested at or above the maximum speed anticipated following a turbine trip from full load.

10.2.3.6 Inservice Inspection

The inservice inspection program for the turbine assembly and valves will include the following:

1. Disassembly of the turbine at approximately 10 year in service intervals during plant shutdown. Inspection of all parts that are normally inaccessible when the turbine is assembled for operation such as couplings, coupling bolts, turbine shafts, low pressure turbine buckets, and high pressure rotors, will be conducted.

   This inspection consists of visual, surface, and volumetric examinations, as indicated below:

   a. Ultrasonic inspection of the tangential entry dovetails and pins of the finger dovetails will be conducted. This inspection should be conducted at intervals of approximately 10 in service years.

   b. A thorough volumetric ultrasonic examination of the high pressure rotor will be conducted. In addition, all accessible rotor surfaces will be inspected visually and by magnetic particle testing. This inspection should be conducted at intervals of approximately 10 in service years.

   c. Visual and surface examination of all low pressure buckets.

   d. 100 percent visual examination of couplings and coupling bolts.

2. Dismantle at least one main steam stop valve, one main steam control valve, one reheat stop valve, and one reheat intercept valve, at approximately 3 1/3 year intervals during refueling or maintenance shutdowns, and conduct a visual and surface examination of valve seats, discs, and stems. If unacceptable flaws or excessive corrosion are found in a valve, all valves of its type will be inspected. Valve bushings will be inspected and cleaned, and bore diameters will be checked for proper clearance.

3. Main steam stop, control, and combined intercept (reheat stop, and intercept valve) valves will be exercised by closing each valve and observing, by the valve position indicator, that it moves smoothly to a fully closed position. This observation will be made by actually watching the valve motion. The testing frequency will be performed in accordance with the Turbine Overspeed Protection Maintenance and Testing Program. The positive closing feature on non return extraction valves is testable locally where partial movement of the valve disc and shaft can also be observed.

10.2.4 EVALUATION

The turbine-generator is protected against destructive overspeed by redundant speed control systems during normal and transient conditions.

To ensure system reliability, the overspeed protection systems are designed to ensure operability under the most severe environmental conditions for which the turbine building is designed. Provision has been made for online testability of both the mechanical and electrical overspeed trip systems. Connections between the turbine and the reactor protection system are redundant, physically independent, and separated and designed to withstand a single failure.

The turbine-generator and related steam handling equipment systems are radioactively contaminated only when there is a steam generator tube rupture resulting in leakage of reactor coolant from the primary to the secondary side of a steam generator. Shielding of the turbine-generator systems is not required because the activity level during operation is minimal and well within safe limits. The equilibrium concentrations of various isotopes in the turbine steam system are essentially the same as the equilibrium concentrations in the main steam system. Tables 11.1-2 and 11.1-3 list these concentrations.

No safety related equipment is located in the turbine building. Safety related systems in proximity of the turbine building are protected from the effects of high and moderate energy turbine generator system piping failures or failure of the connections from the low pressure turbine to the main condenser by barriers or remote location.

10.2.5 REFERENCES FOR SECTION10.2

FIGURE 10.2-1 P&ID ELECTRO-HYDRAULIC CONTROL

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.2-2 (SHEETS 1-3) P&ID TURBINE GENERATOR AND FEED PUMP OIL SYSTEMS

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.2-3 P&ID TURBINE GENERATOR SUPPORT SYSTEMS

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

10.3 MAIN STEAM SYSTEM

The main steam system transports steam from the steam generators to the power conversion systems. This system provides a means of controlled heat release from the nuclear steam supply system during periods of station electrical load rejection or when the condenser is not available. The system also provides steam for various auxiliary services including the steam generator auxiliary feedwater pump turbine, turbine gland sealing, and the auxiliary steam system (Figure 10.3-1). Drains are provided as shown on the turbine plant miscellaneous drains system (Figure 10.3-2).

10.3.1 DESIGN BASES

A portion of the main steam system is Safety Class 2 (QA Category I) and is designed and fabricated in accordance with the ASME Code, Section III, Class 2 requirements as discussed in Section 3.2. This portion of the system extends from the steam generators up to and including:

1. The main steam isolation trip valves
2. The main steam pressure relieving valves
3. The main steam pressure relieving bypass valves
4. The main steam safety valves
5. The motor-operated stop-check valves in the steam lines to the auxiliary feedwater pump turbine.

The portion of the main steam system from the main steam isolation trip valves to the turbine building wall and from the motor operated stop check valves to the auxiliary feedwater pump turbine is Safety Class 3 (QA Category I) and is designed and fabricated in accordance with the ASME Code, Section III, Class 3 requirements as discussed in Section 3.2.

The Safety Class 2 and 3 portions of the main steam system are designated Seismic Category I as defined by Regulatory Guide 1.29 (Section 3.2.1). Seismic Category I design requirements are applied to nonsafety class portions of the main steam system in order that proper operation of safety related equipment is not adversely affected. (This portion includes the steam piping from the main steam isolation trip valves up to the turbine building wall, and from the motor-operated stop-check valves to the auxiliary feedwater pump turbine.)

The remainder of the main steam system is not safety related and is designed and fabricated in accordance with ANSI B31.1 requirements (NNS) as discussed in Section 3.2.

The design pressure and temperature of the main steam system piping and components are the same as the steam generator secondary side design conditions, 1,185 psig and 600°F, respectively.

The steam generators and main steam system are protected from overpressure by the main steam safety valves.

The capacity of main steam safety valves is determined based on the main steam pressure not exceeding 110 percent of steam generator shell side design pressure following loss of load from 100 percent power with a reactor trip. The maximum capacity of each safety valve shall not exceed 970,000 lbm/hr to preclude an uncontrolled plant cooldown and corresponding excessive reactivity excursion due to a failed open valve.

The main steam system delivers steam to the turbine stop valves under NSSS warranted conditions.

The capacity of the turbine bypass portion of the main steam system is described in FSAR Section 10.4.4.1.

The main steam system is designed to ensure that a 30 psi differential between any two steam generators for more than 1 minute during transients and turbine valve testing and a 10 psi differential during normal operation will not be exceeded.

The main steam system design ensures a supply of steam to the turbine-driven auxiliary feedwater pump under all accident conditions.

The main steam system design prevents the uncontrolled blowdown of more than one steam generator following a main steam line break accident.

Main steam piping inside and outside the containment structure has been designed in accordance with the design criteria discussed in Sections 3.7B.3. and 3.9B.3. Analyses have been performed to locate supports and restraints in a manner that will prevent a whipping pipe from having an adverse effect on safety related structures, systems, or components.

10.3.2 SYSTEM DESCRIPTION

Steam from each of the four steam generators is carried in separate carbon steel pipes through containment penetrations and main steam isolation valves to the main steam manifold. Four pipes carry the steam from the main steam manifold to the four main turbine stop and control valves and then to the high pressure turbine. System parameters are provided in the heat balance included in Figure 10.1-2.

Steam leaving the high pressure turbine passes through the moisture separator reheaters to the inlets of the three low pressure turbines and the two steam generator feedwater pump turbines. Each of the steam lines between the reheater outlets and the low pressure turbine inlets is provided with a combined intermediate valve (each comprised of an intercept valve and intermediate stop valve) and a moisture separator relief valve discharging to the condenser (Section 10.4.4).

Main steam safety and main steam pressure relieving valves are provided in each main steam line outside the containment structure and upstream of the main steam isolation trip valves.

A steam line to the steam generator auxiliary feedwater pump turbine steam supply header is connected to three main steam lines inside the containment, upstream of the main steam isolation trip valves.

These lines provide steam for the steam generator auxiliary feedwater pump turbine.

The three steam system supply lines each contain one normally closed air-operated valve. Each of these air-operated valves is provided with dual solenoid actuators. Downstream of the air-operated valves each of these steam lines contains a motor-operated nonreturn containment isolation valve before joining the common header to the steam generator auxiliary feedwater pump turbine.

Steam lines from the main steam manifold supply steam to the turbine bypass system (Section 10.4.4), the single stage reheater of the moisture separator reheaters, the turbine gland sealing system (Section 10.4.3), the auxiliary steam system (Section 10.4.10), and the two steam generator feedwater pump turbines (Section 10.4.7).

10.3.3 SAFETY EVALUATION

The main steam system has been designed to perform its functions under all operating conditions. During normal operation, the main steam system transports steam from the NSSS to the steam and power conversion systems. Under accident conditions the safety related portion of the main steam system provides a heat sink for the reactor, protects the secondary system from overpressure and provides steam to the auxiliary feedwater pump turbine.

The main steam isolation trip valves are provided to isolate the nonsafety related portions of the main steam system under accident conditions. The main steam isolation trip valves also prevent the uncontrolled blowdown of more than one steam generator in the event of a main steam line break accident.

Steam line break accidents include a guillotine (double ended) break of the main steam piping upstream or downstream from the valves. Under such conditions, the mass flow rate, moisture carry over (steam quality), and fluid velocity increase considerably relative to the values at normal operation, their magnitudes being functions of the relief opening size plus system flow demands and power level prior to the break. A flow restrictor is provided in each steam generator outlet nozzle to restrict the rate of steam flow from the steam generators.

If a steam line breaks downstream of the main steam isolation trip valves, closure of these valves stops the flow of steam from the steam generators to the ruptured pipe section. Maximum closing time for the main steam isolation trip valve is 10 seconds from the receipt of the signal to close. Valve closure checks the sudden release of energy in the form of main steam, thereby preventing rapid cooling of the reactor coolant system. Valve closure also ensures a supply of steam to the turbine drive for the turbine driven steam generator auxiliary feedwater pump.

During the first milliseconds following a steam line break downstream of the main steam isolation trip valve, the steam contained in the piping between the steam generator and the pipe break will discharge through the valve. This results in greatly increased mass flow rate and low moisture content steam at high velocity (as established by sonic velocity at valve seat bore).

When the above limited quantity of steam has been expelled, the mass flow rate decreases (as determined by sonic velocity at the steam generator flow restrictor).

As the steam generator continues to blow down, swelling of the water level produces high moisture carryover. The mass flow rate is a function of the steam generator flow restrictor diameter and the steam generator pressure.

If a steam line breaks between the main steam isolation trip valve and the steam generator, the affected steam generator would blow down. The main steam isolation trip valves prevent blowdown from the other steam generators. For a steam line break upstream of the main steam isolation trip valve, the conditions encountered during the first phase of this accident are similar to that described earlier.

The steam line break accidents are discussed in Section 15.1.5.

In the event of a main steam pipe rupture, the motor-operated stop check valves in the steam supply lines to the steam generator auxiliary feedwater pump turbine prevent reverse flow of steam. This ensures that the steam supply line to the steam generator auxiliary feedwater pump turbine inlet is continuously under steam generator pressure.

The main steam system is capable of removing heat from the reactor coolant system following sudden load rejection or trip of the turbine generator unit by automatically bypassing main steam to the condenser through the turbine bypass system (See Section 10.4.4 for steam dump capability), or by relieving to the atmosphere through the main steam safety valves, or the main steam pressure relieving valves if the turbine bypass system is unavailable (due to loss of condenser vacuum or both circulating water pumps in any condenser section not running). Removal of the reactor coolant system sensible heat and core decay heat maintains the main steam pressure at or below the allowable limits. The main steam safety valves have a total flow capacity at accumulated pressure which exceeds 105 percent of maximum full load steam flow, and which is sufficient to prevent the main steam pressure from exceeding110 percent of the steam generator shell side design pressure for the most severe loss of heat sink accident. The main steam pressure relieving valves have a total flow capacity of 15 percent of the maximum operating steam flow at no load pressures. These pressure relieving valves are designed to have sufficient capacity to release decay heat and sensible heat to the atmosphere until such time as the residual heat removal system can assume the task of heat removal.

The steam generator atmospheric relief valve isolation valve can be operated to isolate a steam generator in the event that a steam generator atmospheric relief valve fails to close.

Four main steam pressure relieving bypass valves are provided to ensure a secure path around main steam pressure relieving valves in the event that the primary path is no longer available due

to tornado missile or seismic damage to the discharge silencers, or loss of power or air to the main steam pressure relieving valves. These valves provide the capability to dump steam to the atmosphere remotely from the control room following an SSE coincident with LOP. Thus, a cold shutdown can be achieved with dependence upon only safety grade components. Also, these valves may be used for atmospheric steam dump during recover from a steam generator tube rupture, thus providing a safety grade means to perform a RCS cooldown. The safety grade cold shutdown process is described in Section 5.4.7.2.3.5.

The pressure relieving valves operate during periods when the turbine generator or condenser is not in service, the unit is being started up shut down, or during core physics testing, turbine trip on loss of condenser vacuum, during safety grade cold shutdown or loss of electric power to unit auxiliaries. These valves are normally under automatic control from the steam generator pressure but may be manually positioned from the main control board. Local manual action of the main steam pressure bypass valves may be required during a loss of power in order to permit depressurization of the reactor coolant system. The main steam pressure relieving valves or pressure relieving bypass valves preclude operation of the safety valve during normal operating transients by keeping the main steam pressure below the safety valve setpoints. The main steam pressure relieving control valves are not required for overpressure protection of the unit, as the steam generators are protected by the main steam safety valves.

The air-operated globe valves for the steam generator auxiliary feedwater pump turbine are automatically operated. Information on the steam generator auxiliary feedwater pumps may be found in Sections 10.4.9 and Technical Specifications (16.3/4.7.1.2).

Protection from floods, tornadoes, and missiles is discussed in Sections 3.4.1, 3.3, and 3.5, respectively. Protection from high and moderate energy pipe breaks is discussed in Section 3.6.1.

The main steam system piping supports have been analyzed for forces due to the more severe condition of either turbine trip or seismic events from the steam generators to and including the main steam manifold. The main steam system piping supports from the main steam manifold to the turbine have been analyzed for turbine trip forces only. The main steam system has also been stress analyzed for the forces and moments which result from thermal growth. The main steam system piping within the containment structure has been reviewed for possible pipe rupture and sufficient supports and guides have been provided to prevent damage to the containment liner and adjacent piping, equipment, controls, and electric cables.

The main steam isolation valves, safety valves, and the pressure relieving control valves are missile protected and are housed in the Seismic Category I main steam valve building (Section 3.8.4).

The main steam isolation trip valves are Y pattern type globe valves designed to prevent main steam flow in both the forward and reverse directions. Closing forces are provided by steam pressure from the main steam line.

The main steam isolation valve design has a flow profile minimally affected by seismic accelerations. Other advantages include no significant leakage to the environment. The valve

actuators are designed as an integral unit with the system steam-operated piston actuator integrated in the valve housing (within the valve pressure boundary).

With respect to main steam isolation valve actuation mechanisms, all solenoid valves are provided in redundant pairs and are mounted on the piston cylinder assembly. They are physically separated within the confines of the valve configuration. The valve can operate independently from an outside energy supply (nitrogen) and utilizes system energy to actuate the valve (operating pressure taken up or down-stream of the valve).

The main steam isolation valve body is a forged and welded steel design, see Figure 10.3-4. The "actuator" piston cylinder, valve disc, piston and bonnet are forged steel and are built into the valve body as one cylinder unit, fastened by threaded expansion studs with nuts. By pressurizing or venting of appropriate piston compartment, the isolation valve will open or close. An additional closing force is exerted by springs which keep the isolation valve closed at zero pressure differential. In the closed position of the isolation valve, the hard-faced sealing surface of the valve disc rests on the hard-faced sealing surface of the valve body. In the open position of the isolation valve, the hard-faced back-seat of the valve disc rests on the hard-faced back seat of the piston cylinder, thus sealing off the lower piston compartment from the pressure in the valve body.

The solenoid valves controlling the operating medium (steam) for the piston compartments are grouped in two multi-sectioned control blocks mounted on the piston cylinder. The control lines from the valve inlet side are led internally through the piston cylinder. The control lines from the valve outlet side are led in duplicate and are on the outside of the valve body to the control blocks. The operating medium (steam) is automatically taken either from the inlet side or the outlet side of the valve body depending on which side is pressurized. As shown on Figure 10.3-4, the valve is positioned by appropriate pilot valves (solenoid valves) which admit system steam to the proper valve chambers.

The main steam isolation trip valve is suitable for the following normal operating conditions (at nuclear steam supply system stretch output of 3,666 MWt):

Steam flow (lbm/hr)	4,066,732
Steam pressure (psia)	994
Steam temperature (°F)	544
Steam Quality (%)	99.7

The valves are also suitable for the following design conditions:

Steam pressure (psia)	1,200
Steam temperature (°F)	600

When steam line pressure is inadequate, the main steam isolation valve can be held open using nitrogen supplied at 185 psig. However, the main steam isolation valves are required to be closed with the RCS less than 320°F in Mode 4.

As the piston area is larger than the seating area, there is always a surplus of closing thrust available, which closes the valve safely. The high seating thrust produced as a result of this action ensures tightness of the main seat.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

The main steam isolation trip valves are equipped with provisions for testing by partial valve stroking. The partial stroking is accomplished by opening a solenoid valve to admit steam pressure into the lower piston chamber. After a time delay the solenoid valve for the upper piston chamber opens. After 10 percent travel the position indicating device vents both piston chambers and the valve fully opens to the back seat due to pressure acting on the valve plug.

The main steam isolation valves are tested for full closure during each refueling interval.

The main steam pressure relieving valves, motor operated stop check valves and the air-operated globe valves in the lines to the steam generator auxiliary feedwater pump turbine are full stroke tested at refueling intervals.

Code Classes 2 and 3 piping within the jurisdiction of ASME III were inspected and tested during construction according to articles NC-,ND 5000 and NC-,ND-6000, respectively, of that code. Piping falling within the jurisdiction of ANSI B31.1.0 is inspected and tested during construction in accordance with Paragraphs 136 and 137, respectively, of that code. Preservice and inservice inspections of Class 2 and 3 components will be in accordance with FSAR Section 6.6.

The main steam isolation valve design meets the requirements of Regulatory Guide 1.48 and also the inservice inspection requirements of ASME Section XI.

The main steam isolation valve manufacturer performed the hydrotest on the main steam isolation trip valves using kerosene as the test medium. The use of kerosene as a test fluid is in accordance with the manufacturer's standard test procedures and it has been demonstrated through substantial accumulated past experience that this has no deleterious effects on the material of the pressure boundary. Kerosene has better wetting characteristics than water and, therefore, is advantageous for leak detection.

The kerosene used as the test fluid has the following properties:

Analysis: 90% kerosene + 10% oil (rust preventative oil: Valvoline Tectly 875 - S-1)
Sulfur Content Max. = 0.1%
Chlorine Content Max. = 0.001%
Specific Gravity, 0.805 gr/cm^3 at 15°C
Viscosity (Kinematic), 6.71 Stokes

The above fluid presents no safety hazard problems at the specified hydrotest pressure and temperature.

10.3.5 SECONDARY SIDE WATER CHEMISTRY

The objective of the Millstone 3 chemistry program is to establish effective secondary water-chemistry control to minimize metal corrosion and scale/sludge accumulation in the steam generators.

Secondary chemistry is monitored and controlled by procedures and administrative controls in the Secondary Water Chemistry Program. This program is based upon EPRI PWR Secondary Water Chemistry Guidelines and vendor recommendations.

The secondary water chemistry program includes the following.

- Identification of a sampling schedule for the critical parameters, and of control points for these parameters, for each plant operating mode.
- Identification of the procedures used to measure the value of the critical parameters.
- Identification of the sampling points.
- Procedures for recording and management of data.
- Procedures for defining corrective actions for out-of-specification conditions, including time limits.
- Identification of a) the authority responsible for interpreting the data and initiating actions, and b) the sequence and timing of the administrative events required to initiate corrective action.

The purpose of the secondary side water chemistry control is to minimize metal corrosion throughout the system and subsequently minimize scale/sludge formation in the steam generators. Reduction of this sludge and scale, in conjunction with the stringent chemical control, will prevent or alleviate steam generator component corrosion and/or tube failures.

Chemical/corrosion control is achieved by oxygen scavenging, pH control, steam generator blowdown, and deep bed condensate polishing. Oxygen is scavenged from the feedwater by the injection of hydrazine downstream of the condensate polishers. The pH is controlled by additions of an approved pH control agent via the condensate chemical feed system (Section 10.4.7).

The steam generator blowdown system (Section 10.4.8) is used to lower impurity concentrations, and to remove particulate solids from the steam generator during startup. Some blowdown also is used during operation to supplement the condensate polishing system and to remove solids from the steam generator tube sheet.

During startup and operation, the deep bed condensate polishing system (Section 10.4.6) serves to remove unwanted chemical species and to reduce suspended solids on a continuous basis.

Sea water ingress via the condenser is highly unlikely due to the use of corrosion resistant titanium tubing. However, should any ingress occur, then the condensate polishing system also will remove any deleterious ionic and/or solid species.

Secondary chemistry control parameters are monitored and controlled per the EPRI PWR Secondary Water Chemistry Guidelines.

10.3.6 MAIN STEAM AND FEEDWATER SYSTEM MATERIALS

The material specifications used in the containment pressure boundary are listed in Tables 10.3-1 through 10.3-4.

10.3.6.1 Fracture Toughness

All pressure retaining ferritic materials in the containment pressure boundary are fracture toughness tested in accordance with NE 2300 and NC 2300 of the ASME B&PV Code, Section III, 1971; Winter 1973 Addenda.

Impact property testing was optional in the Code edition in effect on Millstone 3; therefore, impact testing was not imposed on main steam and feedwater systems.

10.3.6.2 Materials Selection and Fabrication

The material specifications used for pressure-retaining component parts in the containment isolation boundary are listed in Appendix I of the ASME B&PV Code, Section III, 1971; Winter 1973 Addenda.

Where austenitic steel is used, the requirements of NRC Regulatory Guide 1.44 are followed. The insulation used with this material is in compliance with Regulatory Guide 1.36. The welding procedures for this material are in compliance with Regulatory Guide 1.31 to the extent specified in Section 6.1.1.1. Further discussion of fabrication, testing, and welding for austenitic steel materials is given in Section 6.1.

The cleaning and handling of all safety related austenitic components were in conformance with Regulatory Guide 1.37 requirements as described in Section 6.1.

All ferritic steel components are thoroughly cleaned, descaled, and coated in accordance with the design specifications. These specifications meet or exceed the requirements of standards described in the Quality Assurance Program Description Topical Report.

Preheat temperatures for welding low-alloy steel are in accordance with Regulatory Guide 1.50.

Welding is performed with welders qualified in accordance with Regulatory Guide 1.71, where applicable.

The degree of compliance to the regulatory guide indicated in this section is found in Section 1.8.

Nondestructive examination procedures for tubular products are in accordance with the requirements of the ASME Code, Section III.

10.3.7 INSTRUMENTATION REQUIREMENTS

The main steam system has steam flow and pressure instruments in each main steam line for main flow-feedwater flow mismatch annunciation, three-element feedwater control, and steam line low pressure isolation signal. These protection and control systems are described in Sections 7.2, 7.3, and 7.7.

A trip valve is installed in each of the four main steam lines for rapid line isolation in the event of a rupture. The actuation signal for each isolation trip valve is redundant and is supplied from the steam line isolation (SLI) signal described in Section 7.3. A bypass valve around each main steam isolation trip valve also closes upon receipt of an SLI signal.

Three parallel air-operated valves with redundant solenoids automatically start the steam generator auxiliary feedwater pump turbine upon receipt of a low-low steam generator level signal. Local and remote pressure indicators monitor operation of the steam generator auxiliary feedwater pump turbine.

Pressure signals are supplied to the steam dump and steam generator feedwater pump turbine control from the main steam manifold. The steam dump control is also supplied a pressure signal from the first stage of the high pressure turbine. These control systems are described in Section 7.7. Pressure signals are provided for NSSS protection and control from the first stage of the high pressure turbine.

A pressure transmitter supplies a high pressure turbine first stage pressure (load) signal to the turbine electro-hydraulic control (EHC) system.

TABLE 10.3–1 MATERIALS OF MAIN STEAM AND FEEDWATER VALVES AND PIPING

Manual Gate, Globe, and Check Valves	
Bodies	SA-105 or SA-216, Grade WCB
	A-105 or A-216, Grade WCB
Bonnets	SA-105, SA-217, Grade WC6
Discs	SA-182, F316; Stellite trim or SA-216, WCB
Studs	SA-193, Grade B7 or A-193, B7
Nuts	SA-194, Grade 2H or A-194, 2H
Air-Operated Valves	
Feedwater Flushing Valves:	
Body	A-217, WC9
Bonnet	A-217, WC9
Plug	17-4 pH ST-ST
Seat	316 SS hard face
Feedwater Pump Discharge Control Valves:	
Body	A-216, WCB
Bonnet	A-217, WC6
Plug	17-4 pH ST-ST
Seat	316 SS hard face
Feedwater Pump Discharge Bypass Control Valves:	
Body	A-216, WCB
Bonnet	A-216, WCB
Plug	CA6NM
Seat	316 SS hard face
Feedwater Bypass Level Control Valves:	
Body	SA-216, WCB
Bonnet	SA-216, WCB
Plug	SB-166 CoCrA
Seat	SB-166 CoCrA
Steam Generator Auxiliary Feedwater Pump Turbine Steam Supply Isolation Valves:	

TABLE 10.3–1 MATERIALS OF MAIN STEAM AND FEEDWATER VALVES AND PIPING (CONTINUED)

Body	SA-216, WCB
Bonnet	SA-216, WCB
Plug	SB-166 INCNL CoCrA
Seat	SB-166 INCNL CoCrA
Manual Globe Valves (2 in and Smaller)	
Bodies	SA-105, or A-105
Bonnets	SA-105, or A-105
Discs	SA-217, WC6 with Stellite or A-276
	Type 410, AMS 5387 Stellite 6
Piping	
Piping (Nominal Size)	
24 inch and smaller	SA-106, Grade B-main steam
	A-106, Grade B-main steam
	SA-106, Grade C-feedwater
	A-106,Grade C-feedwater
	SA-182, F22, Grade C-feedwater
26 inch turbine bypass	A-155, Grade KC70, Cl.1
30 inch, 31.5 inch main steam	SA-155, Grade KC70, Cl.1
32 inch main steam transition piece	SA-155, Grade KC70, Cl.1
36 inch feedwater piping	A-155, Grade KC70, Cl.1
42.25 inch main steam manifold	A-155, Grade KC70, Cl.1
Fittings	
2 inch and smaller	SA-105 or A-105
2.5 inch to 24 inch	SA-234, WPB or
	A-234, WPB
	SA-182, F22
26 inch and larger	SA-234, WPC or WPCW
	or A-234, WPC or WPCW
Flanges	

TABLE 10.3–1 MATERIALS OF MAIN STEAM AND FEEDWATER VALVES AND PIPING (CONTINUED)

All	SA-105 or A-105

NOTES:

SA - Material designation for valves designed to Section III, ASME Code

A - Material designed for valves designed to ANSI B31.1 Code

TABLE 10.3–2 MATERIALS OF MAIN STEAM SAFETY VALVES

Valve body	SA-105
Inlet nozzle	SA-182, F316
Disc insert	ASTM 565 Gr. 616T or ASME SB-637 UNS N0775D Type 3
Yoke	SA-105
Yoke rod	SA-193, Grade B6
Compression screw	SB-164, Cl. A
Spindle	SA-479, TY 316
Studs (inlet flange)	SA-193, Grade B7
Nuts (inlet flange)	SA-194, Grade 2H

TABLE 10.3–3 MATERIALS OF MAIN STEAM PRESSURE RELIEVING VALVES

Valve body	SA-216, Grade WCB
Disc insert	SA-479, Type 316, SA-105 or SA-216, Grade WCB
Bonnet	SA-216, Grade WCB
Bonnet studs or bolts	SA-193, Grade B7
Bonnet nuts	SA-194, Grade 2H or 7

TABLE 10.3–4 MATERIALS OF MAIN STEAM/FEEDWATER VALVES

Main Steam Isolation Trip Valve	
Valve body	SA-105
Bonnet	SA-105
Bonnet studs	SA-193, Grade B16
Bonnet nuts	SA-194, Grade 7
Piston	A-276, Type 410 *
Valve disc	A-276, Type 410 *
Feedwater Isolation Trip Valve	
Bodies	SA-216, Grade WCB
Bonnets	SA-216, Grade WCB
Discs	SA-515, Grade 70, with Stellite
Stem	A-276, Grade 410T
Studs	SA-193, Grade B7
Nuts	SA-194, Grade 2H
Feedwater Flow Control Valves	
Bodies	SA-352, Grade LCB
Bonnets	SA-105
Stem	SA-276, TP316
Plug	SA-182, TPF304, Stellite No. 6
Studs	SA-193, Grade B7
Nuts	SA-194, Grade 2H

* Code Case 1334-3 used in fabrication.

FIGURE 10.3-1 (SHEETS 1-6) P&ID MAIN STEAM AND REHEAT

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.3-2 (SHEETS 1-3) P&ID TURBINE PLANT MISCELLANEOUS DRAINS

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.3-3 P&ID CHEMICAL FEED

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

10.4 OTHER FEATURES OF MAIN STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

The main condenser (Figure 10.4-1) condenses and deaerates steam from the three low-pressure turbine exhausts, the two main feedwater pump turbine exhausts, the turbine bypass control valves, and from various equipment vents and drains.

10.4.1.1 Design Bases

The design bases of the main condenser are:

1. The condenser is nonnuclear class.

2. The condenser is designed for a 17.5°F tube rise at a duty of 7.85 billion Btu/hr and a cooling water flow of 906,668 gpm. At rated power conditions, the temperature rise is expected to be approximately 19.3°F with a heat removal rate of 8.2 billion Btu/hr for an approximate cooling water flow of 840,000 gpm. For physical characteristics and performance requirements of the main condenser, see Table 10.4-6.

3. The condenser maintains normal turbine backpressure for all operating conditions. Backpressure during operation of the turbine bypass system may rise above the normal continuous range but remains within limits specified by the turbine manufacturer.

4. The condenser is designed to accept a 40 percent turbine bypass steam dump from the main steam system. This steam dump permits a 50 percent load rejection without reactor trip, as discussed in Section 10.4.4.

10.4.1.2 System Description

The main condenser is a single-pass, single-pressure, triple-shell unit with two tube banks per shell. Each shell is rigidly supported. Relative movement between the shells and turbine is accommodated by rubber expansion joints in the steam inlets.

Equalizing ducts between the shells equalize pressure and hotwell condensate level. The total hotwell storage capacity of the main condenser approximates 5 minute flow at full load operation. Two feedwater heaters are located in each condenser neck.

Table 11.1-7 lists the anticipated inventory of radioactive contaminants in the condenser. The design concentration of radioactivity in the condenser during normal operation is based on historical design calculations, assuming operation with 1percent cladding defects, coincident with 166 gallons per day steam generator primary-to-secondary leakage.

The anticipated air inleakage into the condenser is 60.0 scfm, calculated by the method given in the Heat Exchange Institute's Standard for Steam Surface Condensers, Sixth Edition. Condenser air removal is discussed in Section 10.4.2.

10.4.1.3 Safety Evaluation

The main condenser is not safety related; therefore, no safety evaluation is required. The following design evaluation demonstrates condenser capability to perform its intended function.

The condenser is designed for operation at maximum calculated unit capability. Impingement baffles protect the tubes from direct steam/water impingement and spray nozzles in the condenser necks dissipate steam from the turbine bypass system (Section 10.4.4).

The following measures are taken to prevent the loss of condenser vacuum:

1. A main condenser evacuation (air removal) system is provided to establish and maintain condenser vacuum. A detailed description of this system design is provided in Section 10.4.2.

2. A vacuum priming system is provided on the condenser waterboxes (circulating water system) to ensure that the condenser tubes are flowing full. This condition maximizes the condenser vacuum. A detailed description of this system design is provided in Section 10.4.5.3.

3. Controls are provided to manually start a second 100 percent capacity air ejector, if necessary. (Section 10.4.2.2).

4. Loss of condenser vacuum has been anticipated and its consequences evaluated in the safety evaluation, Section 10.4.2.3.

5. Instrumentation required to monitor the status of the circulating water system is discussed in detail in Section 10.4.5.5.

The condenser is protected from overpressure by relief diaphragms furnished on the low-pressure turbine exhaust hoods (steam side) and by vacuum breakers on the water boxes (water side). These vacuum breakers open automatically to prevent excessive pressure transients caused by multiple circulating water pump trips.

Corrosion induced tube leakage is minimized by using titanium (ASTM-B 338 Gr. 2) condenser tubes. Titanium is highly resistant to corrosion in seawater and also resistant to ammonia attack and the effects of high velocity steam impingement.

Leakage of seawater into the condenser due to tube-to-tube sheet joint leaks is prevented by the condenser tube sheet design. The tube holes in the tube sheet have three circumferential grooves. The two outer grooves are shallow grooves provided to increase the strength of the tube-to-tube sheet joint when the tubes are roller expanded into the tube sheet. The center groove is machined

such that the groove breaks through the ligaments between the adjacent tube holes and connects with the groove in each of the adjacent holes.

Clean condensate is injected into the interconnecting center grooves at a pressure 10 psi higher than the normal operating pressure in the water boxes. Because the pressure in the interconnecting grooves is higher than the pressure at either face of the tube sheet, any leaks that do develop pass clean condensate rather than permit seawater to enter the condenser.

Leakage from the circulating water system into the condenser due to tube leakage is detected by conductivity sample points in troughs under each tube sheet. Continuous sampling is provided to the turbine plant sampling system to detect any major tube leakage in the hotwells. Each trough sample point and the hotwell sample point nearest the condensate pump suction are monitored continuously and alarmed. When leakage is detected, the affected tube bundle can be removed from service by tripping the associated circulating water pump and breaking vacuum in the water box. The water box may then be entered for tube plugging or other maintenance operations. One tube pass can be isolated without reducing unit load.

An impressed-current cathodic protection system is provided in the condenser water boxes to protect against galvanic corrosion due to the use of dissimilar metals (aluminum bronze tube sheet, copper- nickel water box cladding, titanium condenser tubes).

Monitoring of radioactive leakage into the condenser is not required because there are indirect means for detection; primary-to-secondary leakage into the steam generators is detected by continuous monitoring of the steam generator blowdown. Also, radioactive leakage out of the condenser is monitored by a radiation monitor in the steam jet air ejector discharge line.

Double integrally grooved tube sheets are supplied with seal water from the condensate system in order to prevent inleakage of circulating water at the tube sheets.

Minor condenser tube leakage is detected by on-line sampling of the full condensate flow through the condensate demineralizer mixed bed. Permissible cooling water inleakage and design basis secondary water quality are provided in Section 10.4.6.1. The condenser is designed such that a single tube bundle can be isolated and plugged during plant operation. Major tube leakage is detected by a conductivity alarm in the turbine plant sampling system. Major tube leakage, severe enough to rapidly deplete the condensate demineralizers requires plant shutdown and main condenser tube plugging or replacement.

The potential for hydrogen buildup in the condenser is negligible. Hydrogen entering the condenser is removed by the condenser air removal system.

Flooding due to a complete condenser failure (Section 10.4.5) will not damage any safety related equipment inside or outside the turbine building. The worst case of flooding results from an expansion joint failure at the condenser inlet.

10.4.1.4 Tests and Inspections

Manways are provided in the exhaust neck and hotwell of each condenser shell to give access for cleaning, inspection, and repair as may be required. Manways are also provided in each of the condenser water boxes.

10.4.1.5 Instrumentation Requirements

All instrumentation on the condenser is nonsafety related.

Level controllers and level alarms on the condenser are discussed under condensate and feedwater systems (Section 10.4.7).

High condenser backpressure is alarmed on the main control board and monitored by the computer.

On low condenser vacuum, pressure switches trip the turbine which results in closure of the turbine stop and bypass valves. This isolates the steam source. There is no change in position of the main steam isolation valves for this condition since these valves are only automatically isolated on a steam line isolation signal (described in Sections 7.3 and 15.1.5) which mitigates steam line breaks and/or ensures containment integrity.

Condenser pressure is indicated on the main control board.

Temperature is indicated locally and monitored by the computer.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation (air removal) system (Figure 10.4-2) removes noncondensable gases from the condenser shells.

10.4.2.1 Design Bases

The condenser evacuation system is designed in accordance with the following criteria:

1. The condenser evacuation system is designed to draw the initial vacuum in the condenser shells during startup, maintain vacuum during operation, and dispose of the noncondensable gases from the condenser.

2. The condenser evacuation system is non safety-related and is classified as nonnuclear safety (NNS).

3. The condenser air removal pumps are sized to operate in parallel and to initially reduce condenser pressure from atmospheric to 10 inches HgA in 40 minutes. The capacity of each air removal pump is 3,100 scfm at 10 inches HgA.

4. The steam jet air ejectors are sized to maintain condenser vacuum during normal operation. The capacity of each steam jet air ejector unit is 53.5 scfm at a suction pressure of 1.5 inches HgA.

5. General Design Criteria 60 and 64 are in accordance with the provisions for control and monitoring the release of radioactivity to the environment.

6. Quality Group D requirements are defined in Table I of Regulatory Guide 1.26 (Section 3.2.2).

10.4.2.2 System Description

Two 100 percent capacity steam jet air ejector units and two horizontal, motor-driven condenser air removal pumps are provided.

The condenser air removal pumps are rotary water-ring type pumps, including silencers and seal water cooling systems, and are used to draw initial condenser vacuum.

The steam jet air ejectors are triple element first-stage and single element second-stage units with water cooled inter and after condensers. Motive steam is supplied to the air ejectors from the auxiliary steam supply header (Section 10.4.10) and cooling water is supplied from the condensate system (Section 10.4.7).

Air and noncondensable gases removed from the main condenser shells by the steam jet air ejector units is discharged to Millstone stack via the radioactive gaseous waste system (Section 11.3). Air removed by the condenser air removal pumps is discharged directly to the atmosphere through a vent stack in the condensate polishing enclosure roof.

On indication of low absolute pressure in the condenser, the condenser air removal pumps are manually shut down and one steam jet air ejector unit is manually started. During normal operation, one unit operates with the other unit on standby. On indication of high absolute pressure in the condenser, during normal operation, the second steam jet air ejector unit is manually started.

10.4.2.3 Safety Evaluation

The condenser air removal system is not safety related. The following design evaluation demonstrates the system capability to perform its intended function.

The maximum air leakage into the condenser (Section 10.4.1) is 60 scfm. This leakage is conservative and reflects the anticipated air inleakage after an extended period of plant operation. Normally, one air ejector unit is sufficient to maintain the required vacuum; however, if necessary, both units may be operated in parallel.

The air discharged from the steam jet air ejector units is considered potentially radioactive and is monitored continuously by the effluent radiation monitoring system (Section 11.5.3). The air

removal discharge has a provision for continuous sampling of iodines and particulates during air removal pump operation. The air ejector condenser drains and condenser air removal pump overflow drains are also considered potentially radioactive. The air ejector condenser drains are returned to the main condenser. The air removal pump drains are piped to the turbine building floor drains which are continuously monitored by the process radiation monitoring system (Section 11.5).

Maintaining vacuum in the condenser is necessary for operation of both the turbine bypass system (Section 10.4.4) and the turbine generator unit (Section 10.2). Failure of the condenser air removal system causes a gradual loss of vacuum in the condenser which could ultimately result in turbine generator trip, followed by a reactor trip if the unit load is above 50 percent. Depending upon the magnitude of main steam flow, high condenser pressure may result in the opening of the main steam safety valves and the main steam pressure relieving control valves in the main steam system (10.3).

Continuous venting prevents the buildup of explosive mixtures in the air removal equipment.

10.4.2.4 Tests and Inspections

The steam jet air ejectors are periodically inspected in accordance with the applicable station procedures.

10.4.2.5 Instrumentation Requirements

The condenser air removal system operating parameters are monitored, indicated, and controlled locally or remotely, as follows:

<u>Controls on the Main Board in the Control Room</u>

Control switches with indicating lights for administrative control of:

1. Condenser air removal pumps
2. Condenser air removal pump suction valves
3. Condenser air removal pump seal water pump
4. Condenser vacuum breaker valves

Annunciators that alarm when the following conditions exist:

1. Condenser air removal pump breaker auto trip
2. Condenser low vacuum

An indicator and recorder for condenser vacuum

The Plant Computer

1. Condenser vacuum
2. Condenser air removal pump breaker position
3. Condenser air removal pump motor overcurrent
4. Condenser air removal pump breaker auto trip or overcurrent

Local Flow Indicators

Local flow indicators are provided on the outlet of the air ejectors to check periodically for condenser air leakage.

Radiation Monitoring Equipment

Section 11.5 describes the radiation monitoring equipment.

10.4.3 TURBINE GLAND SEALING SYSTEM

The main turbine, feed pump turbines, and the main steam stop and control valves, and the combined intermediate valves are provided with gland seal steam and leak-off (Figure 10.4-3). The turbine gland sealing system is not safety related.

10.4.3.1 Design Bases

The turbine gland sealing system (Figure 10.4-3) prevents air leakage into, and collects steam leakage out of the turbines and valve stems. The steam seal system provides this function automatically from startup to full load.

The turbine gland sealing system is designed in accordance with the turbine generator manufacturer's standards. Connecting piping, valves, and equipment are designed in accordance with Quality Group D Standards as defined in Regulatory Guide 1.26.

10.4.3.2 System Description

The turbine gland sealing system consists of three steam sources: main, auxiliary, and extraction steam; a seal pressure controller, steam seal header, a steam packing exhaust condenser, two full-capacity exhaust blowers and the associated piping, valves, and instrumentation. The turbine gland sealing system is normally operated with extraction steam from the fourth point extraction supplemented by main steam during low load operation. The use of extraction and main steam is controlled by a split range pressure controller which maintains the gland steam header pressure by first admitting extraction steam and, if necessary, main steam.

The turbine gland seal system is designed to provide a continuous supply of steam between 3 to 5 psig to the turbine shaft glands.

When main steam is unavailable, the gland steam seal system operates on 150 psig auxiliary steam.

During low load operation (startup and shutdown), steam is taken from the main steam lines ahead of the turbine stop valves. This pressure is reduced by throttling the steam seal feed valve which seals the turbine automatically with 25 percent rated throttle pressure and normal packing clearances.

To seal at low throttle pressures or with worn packings, the steam seal bypass feed valve may be used in parallel with the steam seal feed valve.

As pressure in the turbine increases with load, the pressure packings and the steam seal feed valve extraction source contribute steam to the steam seal header.

Steam packing unloading valves are provided to vent excess gland seal steam to the condenser if necessary to maintain 5 psig in the gland steam header. Relief valves on the steam seal header prevent excessive steam seal pressure in the event of a control system failure.

A mixture of air and steam drawn from the shaft packing is condensed in the steam packing exhauster condenser. During plant operation, the steam packing exhauster condenser is cooled by the main condensate flow (Section 10.4.7). The recovered condensate is returned to the main condenser hotwell via a loop seal and trap. The noncondensable gases are expelled to the atmosphere by one of the two motor-driven blowers mounted on top of the steam packing exhauster condenser.

10.4.3.3 Safety Evaluation

The turbine gland sealing system is not safety related and there is no requirement for a safety evaluation which would demonstrate compliance with the criteria which would be applied to a safety system.

There is no radiation monitoring at the gland seal condenser vent as radioactive gaseous releases fall within the total unmonitored steam release specifications from the turbine building as defined in NUREG-0017, April 1976, Section 2.2.6.

10.4.3.4 Tests and Inspections

All tests and inspections of equipment which are part of the turbine gland sealing system are as described in the manufacturer’s instructions.The gland sealing system is normally in operation and no special tests are required to verify operability.

10.4.3.5 Instrumentation Requirements

Control switches and indicator lights are provided on the main control board for manual operation of the steam packing exhauster blowers.

The following valves have control switches and position indicator lights on the main control board:

Main steam gland seal steam supply valve
Auxiliary steam gland seal supply valve
Gland seal steam feed bypass valve
Manual steam packing unloading valve

A Distributed Control System (DCS) is utilized to control the steam seal pressure control valves.

A direct sensing pressure control valve is utilized as the steam packing unloading valve.

The following instrumentation is located on the main control board:

Annunciators that alarm when the following conditions exist:

Steam packing exhauster condenser level High
Steam seal feed pressure High
Steam seal feed pressure Low
Steam packing exhaust vacuum Low

Indicators that monitor the following parameters:

Steam packing exhaust vacuum
Steam seal steam feed pressure

Local indicators are provided to monitor the steam packing exhauster condenser vacuum and the steam seal feed pressure.

Local flow elements are installed for performance testing of the system.

10.4.4 TURBINE BYPASS SYSTEM

The turbine bypass system is contained in the main steam system (Section 10.3), as shown on Figure 10.3-1.

10.4.4.1 Design Basis

For the range of NSSS design parameters, a rapid ramp load decrease equivalent to 50 percent of rated thermal power / turbine load at a maximum turbine unloading rate of 200 percent per minute can be accommodated without a reactor or turbine trip and without lifting the main steam safety valves. This system design capability will accommodate up to two steam dump valves out of service.

The turbine bypass system is designed in accordance with ANSI B31.1. The system is not required for safe shutdown and is not safety related. It is required only to provide flexibility of operation and a controlled cooldown.

The capacity of any single turbine bypass valve does not exceed 970,000 lb/hr of steam at the main steam system design pressure, 1,185 psig, as specified by the nuclear steam system supplier. The failure of a turbine bypass valve to close will not cause an uncontrolled plant cooldown and corresponding excessive reactivity excursion.

The design pressure and temperature of the bypass piping from the main steam manifold up to and including the turbine bypass valve is the same as the steam generator secondary side design conditions, 1,185 psig and 600°F. The piping after the bypass valves has a design pressure of 250 psig and a design temperature of 600°F.

10.4.4.2 System Description

The turbine bypass system includes a turbine bypass header, branching from the main steam manifold in the main steam system (Section 10.3), and individual bypass lines connecting the bypass header to the condenser. One manual isolation valve and a turbine bypass valve are mounted in series on each individual turbine bypass line.

The full capacity of the turbine bypass system is equally distributed among the three condenser shells to ensure an even heat load and to minimize uneven turbine exhaust pressures and uneven expansion of the low pressure turbine casings.

The details of the arrangement of the turbine bypass valves and associated controls are shown on Figure 10.3-1. A total of nine bypass valves are provided, three in each condenser section. The bypass valves are 8 inch, carbon steel globe valves with spring and diaphragm air operators. Each of the valves is designed to pass a minimum of 70,600 lb/hr and a maximum of 970,000 lb/hr at pressures ranging between 125 psig and 1185 psig, respectively. This ensures smooth control of the steam dump flows over all steam operating pressure ranges. When the valves are modulated open, one valve from the bank of three valves in each condenser opens first, followed by succeeding valves opening in similar order for the remaining six valves. The methodology of the setpoints for actuating the bypass valves is described in Section 10.4.4.5.

After a normal orderly shutdown of the turbine generator leading to unit cooldown, the turbine bypass valves will be used for several hours to release steam generated from reactor coolant system sensible heat. This is accomplished by first manually bypassing the lo-lo-T_{avg} interlock.

Reactor cooldown, programmed to minimize thermal transients and based on sensible heat release, will be affected by a gradual adjustment of the turbine bypass valves until the cooldown process is transferred to the residual heat removal system.

10.4.4.3 Safety Evaluation

All or several of the turbine bypass valves will be opened under the conditions described in this section, providing the condenser is available.

During startup, shutdown, operator license training, or physics testing, the turbine bypass valves will be actuated remote manually from the main control board.

All turbine bypass valves are prevented from opening on loss of condenser vacuum, or both circulating water pumps in any condenser section not running and in such a case, excess steam pressure will be relieved to the atmosphere through the main steam safety and main steam pressure relieving valves or the pressure relieving bypass valves. Redundant safety interlocks are provided to reduce the probability of inadvertent opening of the turbine bypass valves (Section 7.7).

The turbine bypass system high energy lines are located remote from any safety related components or systems. The turbine speed control system is not safety related. However, should the turbine speed control system be damaged by the failure of a bypass system high energy line, the redundancy built into the turbine control system (Section 10.2) makes the possibility of a turbine overspeed situation unlikely. Further, an analysis has determined that the probability of damage to safety related equipment resulting from a turbine overspeed is acceptably low.

The failure mechanisms, which were accommodated in the design of the turbine bypass system, are internal failures of the valves themselves, loss of instrument air to the valves, loss of electrical power to the valves, operator error, and spurious signals to the valves.

10.4.4.4 Tests and Inspections

During refueling shutdowns, the turbine bypass valves and turbine bypass system controls will be inspected and tested for proper operation.

All turbine bypass system piping will be inspected and tested in accordance with Paragraphs 136 and 137, respectively, of ANSI B31.1.

10.4.4.5 Instrumentation Requirements

On a large external electrical load decrease (maximum of 50 percent), the turbine bypass system creates an artificial load on the steam generators to prevent the reactor from tripping. Reactor power can be decreased at a rate up to a maximum of 5 percent/minute until it matches the turbine generator load requirements. At that point, the bypass valves are fully closed. When a load rejection occurs, if the difference between the required temperature setpoint of the reactor coolant system and the actual average temperature exceeds a predetermined amount, a signal will actuate

the turbine bypass to maintain the reactor coolant system temperature within control range until a new equilibrium condition is reached. The required number of turbine bypass valves can be actuated quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from the loss of load. The Reactor Control System and Turbine bypass control systems are discussed in detail in Sections 7.7.1 and 7.7.2. The turbine bypass valves have the capability of going from full closed to full open within 3 seconds after receipt of an actuation open signal. T_{ref} is a function of load and is set automatically. The turbine bypass valves close automatically as reactor cooling conditions approach their programmed setpoint for the new load.

On a reactor trip, the turbine will trip and the turbine bypass system creates an artificial load on the steam generators to prevent lifting of the main steam safety valves (Section 10.3). The control is automatically transferred from the load rejection controller to the turbine trip controller. An error signal exceeding a set value of auctioneered reactor coolant T_{avg} minus a preset turbine trip controller setpoint fully opens all turbine bypass valves. The valves discharge to the condenser for several minutes, thereby removing the thermal output of the NSSS without exceeding acceptable core and reactor coolant system limiting conditions. Following a reactor trip, the turbine bypass valve signal may be transferred from the turbine trip controller to the steam line pressure controller. In this mode, main steam line pressure is compared with a predetermined setpoint to produce the controller output signal for valve modulation. Atmospheric steam discharge is not required during these conditions, provided that no block signal, such as loss of condenser vacuum, is present.

The following controls and instrumentation for the turbine bypass system are located on the main control board:

1. Steam dump control mode selector switch positions RESET-T/AVG-STEAM PRESSURE.

2. Steam dump interlock selector switches (Trains A and B) with positions OFF/RESET-ON-BYPASS INTLK.

3. Position indication lights for the turbine bypass valves.

4. Steam header pressure controller AUTO/MANUAL station.

5. Steam generator atmospheric relief valve pressure indicating controllers with AUTO/MANUAL feature and valve position indicator lights.

6. Control switches and valve position indicator lights for the main steam pressure relieving isolation valves

7. Steam dump demand signal indicator.

8. Annunciators:

a. Steam pressure relieving valve in local control

b. Main steam relief valve not closed.

c. Main steam pressure relieving isolation valve in local control.

9. Status lights:

a. Steam dump interlock bypassed.

b. Turbine load rejection armed.

c. Turbine bypass valves armed for opening.

d. Condenser available for steam dump.

e. Turbine bypass valves trip open signal present.

The following instrumentation and controls for the turbine bypass system are located on the auxiliary shutdown panel:

1. REMOTE/LOCAL control selector switches for the main steam pressure relieving valves and valve position indicator lights.

2. Manual pressure control stations for the main steam pressure relieving valves.

3. REMOTE/LOCAL control selector switches for the main steam pressure relieving isolation valves.

4. Control switches with position indicating lights for the main steam pressure relieving isolation valves.

The following parameters are monitored by the plant computer:

1. Turbine bypass steam temperature at discharge of each bypass valve.

2. Open and closed position of each main steam pressure relieving isolation valve

10.4.5 CIRCULATING WATER AND ASSOCIATED SYSTEMS

The circulating water system (Figure 10.4-4) is a once-through cooling water design utilizing an onshore Niantic Bay intake and a quarry surface discharge. The system provides debris-free salt water flow to the main condenser where waste heat from the thermal power cycle is collected for removal to the quarry. In addition, the circulating water discharge tunnel receives heated water from the service water system and intermittent discharges from the liquid waste system and the steam generator blowdown flash tank for discharge to the quarry (Section 11.2).

The associated systems are the traveling screen wash and disposal system and the vacuum priming system. The traveling screen wash and disposal system (Figure 10.4-4) removes debris from the seawater used as cooling water in this unit. Fish removal equipment is incorporated into the screen wash design. The vacuum priming system (Figure 10.4-2) initially primes and continuously removes air from the circulating water lines, the condenser water boxes, and the circulating water discharge tunnel and outfall structure to create and maintain a siphon in the tube side of each of the main condensers and to ensure that all tubes are filled.

Table 10.4-1 contains design and performance characteristics for these systems.

10.4.5.1 Design Bases

The circulating water and associated systems are designed in accordance with the following criteria.

Circulating Water System

The circulating water system is not safety related and is designated nonnuclear safety class except for the circulating water discharge tunnel and portions of the circulating and service water pump house (Section 3.8.4). A failure of this system, with the exception of the circulating water discharge tunnel and portions of the circulating and service water pump house, does not affect any safety related equipment or the capability to shut down the primary plant safely. The circulating water discharge tunnel has QA Category I designation and has been designed Seismic Category I to ensure availability as the discharge conduit for the service water system (Section 9.2.1). All portions of the circulating and service water pump house which support, or, by failure, could damage the service water system (Section 9.2.1) are designated Seismic Category I.

The circulating water system is designed as a once-through system to remove 7.5×10^9 Btu/hr of waste heat from the power conversion cycle. The rejected heat is transferred to the circulating water as it flows through the condenser. The predicted temperature rise is expected to be 19.3°F with a heat removal rate of 8.2 billion BTU/hr for an approximate cooling water flow of 840,000 gpm at rated power conditions.

The circulating water piping and expansion joints are designed for 50 psig internal pressure and full vacuum. The discharge tunnel is designed for +7 psig and -8.7 psig internal pressure.

The circulating water discharge tunnel is designed to receive heated water from the service water system and intermittent discharges from the liquid waste system and the steam generator blowdown flash tank for discharge to the quarry.

The circulating water system is designed to permit thermal backwashing of the inlet piping and intake pump bays for biofouling control.

Traveling Screen Wash and Disposal System

The traveling screen wash and disposal system is nonsafety related.

The traveling screen wash and disposal system removes debris and fish from the seawater before it enters the circulating water system and the service water system (Section 9.2.1). The system provides wash water at a pressure of 85 psig for high pressure spray nozzles for the removal of debris from the traveling water screens and for makeup flow to the fish sluiceway. The system also provides wash water at 10 to 35 psig for low pressure spray nozzles for the removal of fish from the traveling water screens and for sluicing of removed fish. A screenwash flow rate of approximately 4,000 gpm is required for slow speeds screen operation and approximately 8,000 gpm for fast speeds screen operation.

The traveling screen wash and disposal system was designed to supply water to the Millstone 3 condensate demineralizer component cooling water heat exchanger which is removed from service and backs up the water supply to the Millstone 2 condensate demineralizer component cooling water heat exchanger. The system also provides an alternate means of supplying water to the chemical feed chlorination system, if required.

Vacuum Priming System

The vacuum priming system is nonsafety related.

The vacuum priming system (Figure 10.4-2) consists of two subsystems: the station system and the yard system. The station system removes a maximum air flow of 1,675 acfm at a vacuum of 26 in Hg. The yard system removes a maximum air flow of 540 acfm at a vacuum of 10 in Hg. During normal circulating water system operation, the actual air flow and vacuums are less than the design values.

10.4.5.2 System Description

Circulating Water System

The circulating and service water pump house is divided into six bays which supply seawater to six circulating water pumps: four service water pumps (Section 9.2.1) and two screenwash pumps. Flow to each bay passes through a trash rack, which is cleaned by a trash rake and a traveling water screen.

Each of the six, one-sixth capacity, motor-driven, mixed flow, vertical, wetpit circulating water pumps has a design flow of 152,000 gpm with a total dynamic head (TDH) of 27 feet. Pump speed is normally controlled by a Variable Frequency Drive (VFD). In the event that VFD mode for a given pump is deemed undesirable, the VFD can be by passed, allowing operation at rated speed; however, no speed control is available in this condition. This operation requires that the affected circulating water pump be shut down during the transfer to the bypass mode of operation. The circulating water flows from the pumps to the condenser (Section 10.4.1) through six independent inlet pipe lines. The circulating water discharges from the condenser though six independent outlet pipe lines into a common concrete circulating water discharge tunnel which runs to a seal pit at the quarry. From the quarry, the water passes through a channel into Long Island Sound.

A motor-operated valve is installed at each circulating water pump discharge and in each condenser circulating water outlet pipeline. Each pair of valves is used to isolate half of a condenser shell. Operation with one or more circulating water pumps out of service is possible, depending on plant load and circulating water temperature. A motor-operated crossover valve is installed between adjacent condenser inlet waterboxes to permit use of both condenser tube bundles in a shell with either one of the associated circulating water pumps. A motor-operated backwash valve is installed between adjacent condenser outlet waterboxes to permit thermal backwashing of the condenser.

Heat shock treatment (thermal backwash) controls marine growth in the circulating water pumphouse bays and condenser inlet piping. The heat shock treatment is accomplished by the method described in Mode E below. This operation allows the circulating water that has passed once through half of a condenser shell to reverse and pass back again through the other half of the condenser shell thereby increasing its temperature. The effect of passing hotter circulating water in the reverse direction through the system is to kill marine growth. This process is repeated to treat each pump bay and inlet pipe.

The water velocity of approximately 9 fps in the inlet piping and 10 fps in the discharge piping also contributes to the prevention of marine organisms adhering to, and growth within, the circulating water lines.

Chlorination is performed on an intermittent basis in the circulating water system to prevent biofouling of condenser tubes. Chlorination equipment is installed to prevent biofouling of the service water system (Section 9.2.1).

There are five planned modes of operation of the circulating water system:

Mode A: To dissipate all rejected heat from the power conversion cycle.

All six circulating water pumps operate and pump water through six independent inlet lines, through six condenser half shells, and through six independent discharge lines to the discharge tunnel.

Modes B and E: To provide hot water for thermal backwashing of the condenser inlet piping and intake pump bays while dissipating all rejected heat from the power conversion cycle.

Mode E: Four circulating water pumps operate normally as discussed under Mode A.

Mode B: The pair of pumps involved in the thermal backwash have one pump operating and one pump stopped. Water is pumped through the inlet piping, through a condenser half shell. A portion of the flow is rerouted across the condenser outlet cross-connect pipe back through the adjacent condenser half shell. One condenser outlet valve is closed while the other is throttled. The portion of the total flow that is passed through the adjacent

condenser then flows through the condenser inlet piping back to the pump house where it is discharged through the stopped pump. The remaining portion of flow passes to the discharge tunnel through the throttled condenser outlet valve.

Mode C: To dissipate all rejected heat from the power conversion cycle while one pump is out of service.

Four circulating water pumps operate normally as discussed under Mode A.

The partner pump of the pump out of service is operating and pumps water through the condenser inlet piping. At the condenser inlet water box flow is split by opening the condenser inlet cross-over valve. Water flows through both sides of the condenser shell and discharges through two independent lines to the discharge tunnel.

Mode D: To dissipate all rejected heat from the power conversion cycle during reduced unit load or during winter months.

Only three of six circulating water pumps operate and pump water through their respective condenser inlet piping. The flow, at each condenser, is split between inlet waterboxes as discussed under Mode C at cross-over valves. The flow is discharged through the six independent discharge lines to the discharge tunnel.

Traveling Screen Wash and Disposal System

The traveling water screens are located upstream of the circulating water pumps and consist of three-eighth inch mesh panels with fish trays attached to each panel. The screens have four-speed motors.

The screens are automatically operated according to the differential water level across each screen. The screens are also started by an automatic timer every four hours and run for 1.25 screen revolutions. All six traveling screens and one screenwash pump start simultaneously. Two full-size screen wash pumps each have a design flow of 4,000 gpm with a total dynamic head of 235 feet. One pump operates when the traveling screens are in slow speed and both pumps when the screens are in fast speed. The operating modes of the pumps are manually changed on a regular basis to maintain uniform wear on pumps. The screen wash pumps take suction from the intake pump well and discharge to a manifold supplying each traveling water screen with high pressure wash water and low pressure fish flush water. Individual trash and fish troughs collect and sluice debris and fish received from the screens. The debris is removed from the trash trough by a motorized conveyor system to a trash container for removal. The fish are directed from the fish trough to a fish sluiceway which returns them directly to Long Island Sound.

The traveling water screens also have the capability of reverse rotation, which is used in conjunction with the condenser backwashing sequence to remove any debris which has accumulated in the inlet waterboxes and pump bays.

The screen wash pumps were designed to supply water to the condensate demineralizer component cooling water heat exchanger which was removed from service (Section 9.2.2.6).

A cross connection is provided from the Millstone 3 screen wash system to the Millstone 2 condensate demineralizer component cooling water heat exchanger. This provides an alternate source of water to that system in the event that the Millstone 2 condensate demineralizer service water pump is out of service.

Provision is also made for the screen wash pumps to supply water to the chemical feed chlorination system, if required.

Vacuum Priming System

The vacuum priming system primes the circulating water system prior to starting the circulating water pumps and continuously removes air from the discharge tunnel and condenser waterboxes during circulating water system operation to maintain a siphon in the system. The system comprises two independent subsystems, each including a vacuum tank and two full capacity vacuum pumps.

The station vacuum priming system is located in the turbine building and removes air from the inlet and outlet condenser waterboxes. Air collects in vacuum priming domes at the top of each water box and is drawn by vacuum to a common vacuum tank. Vacuum is maintained on the tank by the vacuum priming pumps which discharge the collected air directly to the atmosphere. Moisture which accumulates in the vacuum priming tank is drained by gravity to the circulating water discharge tunnel.

The yard vacuum priming system is located in the yard vacuum priming pumphouse and removes air from an air collection cap on the roof of the circulating water discharge tunnel seal pit.The operation of this system is similar to the station vacuum priming system.

Each subsystem has two full size, liquid ring, centrifugal type vacuum priming pumps. One pump in each system is normally running with the second pump on standby. The operating modes of the pumps are manually changed on a regular basis to maintain uniform wear on the pumps.

10.4.5.3 Safety Evaluation

The circulating water system is not safety related except for the circulating water discharge tunnel and portions of the intake structure. Section 3.8.4 discusses the circulating water discharge tunnel and intake structure. Failure of the circulating water system or any of its components, with the exception of the discharge tunnel and portions of the intake structure, will not damage or flood any safety related system or component.

The following design evaluation demonstrates the system capability to perform its intended function.

Circulating Water System

All six circulating water pumps are normally in service and in Variable Freqency Drive (VFD) mode. If a circulating water pump is out of service, operation of the unit can be continued, but the unit output may be reduced, depending on circulating water inlet temperature at that time. All safety related equipment in other systems required for safe shutdown of the facilities and/or required to limit the consequences of an accident is suitably protected from potential flooding caused by rupture of the non-Category I pipe and components of the circulating water system. Internal plant protection is provided by watertight areas specifically designed for such flooding conditions, by elevation, or by system and component design to ensure that such failures are not possible, as discussed under Circulating Water Expansion Joint Rupture, in this section.

Leakage of seawater from the circulating water system into interfacing systems is minimized by the use of highly corrosion resistant materials as barriers between the circulating water system and its interfacing systems. The most prominent of these barriers is the condenser (Section 10.4.1) with tubes fabricated from titanium, which is highly reliable for seawater application. The tube material minimizes erosion due to high steam entrance velocity and protects the insides of the tubes from damage which could be caused by local high velocity circulating water. To further prevent leakage of seawater into the condenser hotwell, aluminum-bronze tube sheets of double integral design are provided. Seal water from the condensate system (Section 10.4.7) is injected into each inlet and outlet tube sheet at a pressure which is greater than the operating pressure of the circulating water system.

Should any seawater leakage occur from the circulating water system into interfacing systems, this leakage is detected in the condenser hotwell by the turbine plant sampling system (Section 9.3.2.2). Section 10.4.1 discusses the detection of seawater leakage into the condenser.

The circulating water system is protected from excessive pressure transients caused by multiple circulating water pump trips deriving from loss of all electrical power. Vacuum breaker valves, located on each condenser inlet and outlet water box, are automatically opened by any two circulating water pumps tripping within one minute of each other. Hydraulic transient analyses were performed on the circulating water system to determine the most critical operating conditions which would yield the most severe transient pressures (both positive and negative) within the system. It was determined that a loss of power which leads to a simultaneous loss of all six circulating water pumps would produce the most severe pressures. The design transient pressures for the circulating water system, based on loss of power and opening of the vacuum breaker valves, fall within the maximum design pressure/vacuum envelope of the circulating water system.

Circulating Water Expansion Joint Rupture

There are no essential systems or components required for safe shutdown or to mitigate the effects of an accident, located within the turbine building which could be affected by flooding due to a circulating water pipe or expansion joint rupture. In addition, there are no passageways, pipe chases, or cableways that could be rendered inoperable by flood waters generated by a complete rupture of a main condenser circulating water expansion joint. However, a pipe tunnel is provided

at the basement floor, at elevation 14 feet 6 inches, in the turbine building, connecting the turbine building to the safety related auxiliary building. This tunnel is totally sealed with a fire barrier at the auxiliary building and will prevent any water from entering the auxiliary building.

High water level in the condenser circulating water discharge pit sounds an alarm in the control room enabling the operators to stop circulating water flow through the circulating water piping in 60 seconds; however, for design purposes, it is assumed that operator action is delayed for 15 minutes. Within 15 minutes the total amount of water spillage into the turbine building could be approximately 2,250,000 gallons. This water results in a water level at approximately elevation 21 feet-6 inches. This level of water does not affect any essential systems or components.

However, the sump alarm system that is provided to detect flooding in the Turbine Building is not safety-related. Therefore, a circulating water expansion joint rupture in the Turbine Building could result in internal flooding until the water level reaches elevation 28 feet (assuming no operator action). To compensate for this, the siding panel with pressure release feature is provided at elevation 24 feet 6 inches of the Turbine Building. This siding panel will blow out if the floodwater reaches elevation 28 feet inside the Turbine Building. This panel is located on the west side of the Turbine Building, away from several Category I structures which are located east of the Turbine Building. Therefore, continued operation of the circulating water pumps will not result in damage to safety-related systems or components.

A circulating water expansion joint rupture in the turbine building could result in internal flooding until the water level reaches elevation 28 feet. The sump alarm system that is provided to detect flooding in the turbine building is not safety-related. To compensate for this, the siding panel with pressure release feature is provided at elevation 24 feet 6 inches between column lines A39 and A43 of the turbine building. This siding panel will blow out if the floodwater reaches elevation 28 feet inside the turbine building. This panel is located on the west side of the turbine building, away from several Category I structures which are located east of the turbine building. Therefore, continued operation of the circulating water pumps will not result in damage to safety related systems or components.

Traveling Screen Wash and Disposal System

Although the seawater must pass through the traveling water screens prior to entering the service water system, the service water pumps will function properly when the traveling screen drive motors are not operating. The traveling water screens are capable of manual operation and can also be manually cleaned. Because the capacity of the service water pumps is a small percentage of the traveling water screen capacity (less than 9 percent), gradual blockage of the traveling water screens with debris still allows sufficient flow for operation of the service water pumps. If the screens become blocked to the extent that the differential water level across a screen exceeds; 36 inches for screens upstream of service water pumps or 42 inches for screens upstream of screenwash pumps, the circulating water pump is automatically tripped. However, even with a 36 inch differential and low tide, there is adequate net positive suction head for the service water pumps.

There is no dependence on the traveling screen wash and disposal system for safe plant shutdown or following a design basis accident.

Vacuum Priming System

The vacuum priming system is a nonsafety related system. Failure of the vacuum priming system or any of its components will not damage any safety related system or component.
Loss-of-vacuum capability at the condenser water boxes reduces circulating water flow to the condenser with some tubes flowing partially full or empty, which reduces the unit output. The loss-of-vacuum capability at the circulating water system discharge structure reduces circulating water flow with the discharge tunnel flowing partially full, which reduces unit output.

10.4.5.4 Tests and Inspections

Circulating Water System

All components of the circulating water system are normally in service. Therefore, no testing of any of these components is required.

Traveling Screen Wash and Disposal System

All components of the traveling screen wash and disposal system operate intermittently on a daily basis. Therefore, no testing of any of these components is required. Automatic operation of the traveling water screens, screen wash pumps, and debris conveyor is checked during initial operation and at frequent intervals thereafter.

Vacuum Priming System

One vacuum priming pump and associated equipment are normally in service in both the station and yard systems at any time. Because the vacuum priming pumps and associated equipment alternate for operation, no testing is required.

10.4.5.5 Instrumentation Requirements

Circulating Water System

The circulating water pumps and all motor operated valves are manually operated from the control room. The circulating water pump motors are provided with speed controllers at the main control board to manually set and monitor percent speed. Phase current is monitored on the Plant Process Computer through inputs from the Variable Frequency Drive (VFD). When the VFDs are not in use, ammeters located on the main control board and at the switch gear will be used to monitor phase current. Six temperature resistance-detectors (RTDs) are provided for the motor windings on the circulating water pumps: two are utilized, the hottest point for an alarm on the main control board and the second hottest for a computer point; the other four are spares. The motor sleeve bearing and thrust bearing temperatures are monitored by the computer. Circulating water pump discharge pressure is monitored by a local indicator and the computer.

Condenser circulating water inlet and outlet temperatures are monitored by the computer and local temperature indicators.

Valve position indicators are provided on the main control board for the condenser outlet valves in addition to the indicator lights provided for all the circulating water motor operated valves.

High level (1 foot) in the condenser discharge pit sump is alarmed in the control room.

Traveling Screens Wash and Disposal System

One screenwash pump is automatically started by a 6 inch differential water level to provide wash water through the spray nozzles associated with Slow 1 speed screen operation of five feet per minute. A 7 inch differential water level results in screen speed of rotation increase to Slow 2 at 10 feet per minute. A 9 inch differential water level automatically starts the second screenwash pump to provide additional wash water for screen speed Fast 1 at 16 feet per minute. A 10 inch differential water level results in screen speed increase to Fast 2 at 32 feet per minute. High differential (18 inches) level across any traveling water screen is alarmed in the Control Room. High-High differential alarm (42 inch for “A” and “F” Bays with screenwash pumps, and 36 inch for “B,” “C,” “D,” “E” Bays with service water pumps) automatically trips the associated circulating water pump. Traveling screen differential level is indicated on the main control board. High trash rack differential level (6 inches) is alarmed in the Control Room.

Vacuum Priming System

In each vacuum priming subsystem, one pump is normally operating and one pump is in standby. The standby pump automatically starts on high air pressure in the vacuum priming tanks and stops on low air pressure. Low vacuum in the vacuum priming tank is alarmed in the control room.

The circulating water systems operating parameters are monitored, indicated, and controlled, remotely or locally, as follows:

The following controls and instruments are located on the main control board in the control room:

Control switches and indicating lights for:

1. Circulating water pumps

2. Circulating water pump discharge valves

3. Circulating water pump bearing lubricating water supply valves

4. Condenser crossover valves

5. Condenser backwash valves

6. Condenser outlet valves

7. Screenwash pump

8. Refuse trough water supply valve

9. Vacuum priming pump

Annunciators that alarm when the following conditions exist:

1. Circulating water breaker auto trip/overcurrent

2. Circulating water pump stator winding temperature High

3. Condenser pressure differential High

4. Circulating water pump lube water strainer differential pressure High

5. Circulating water pump lube water pressure Low

6. Circulating water discharge pit level High

7. Trash rack differential level High

8. Screenwash pump auto trip/overcurrent

9. Screenwash discharge header pressure Low

10. Traveling screen differential water level Low

11. Screenwash strainer differential pressure High

12. Vacuum priming tank vacuum Low

13. Vacuum priming seal water flow Low

14. Vacuum priming pump auto trip

15. Variable Frequency Drive (VFD) alarm

16. VFD fault

Indicators that monitor the following parameters:

1. Circulating water pump amperage

2. (Deleted)
3. Condenser outlet valve position
4. Screenwash pump amperage
5. Traveling screen speed
6. Screenwash pump discharge valve position
7. Screenwash pump running for the condensate demineralizer system
8. Traveling screen differential water level
9. Seal water circulating pump
10. Seal water replenishing valve
11. (Deleted)
12. (Deleted)
13. VFD percent speed: setpoitn and actual

The following parameters are monitored by the plant computer:

1. Circulating water pump motor overcurrent
2. Circulating water breaker auto trip
3. Circulating water pump motor sleeve bearing temperature
4. Circulating water pump motor stator winding temperature
5. Circulating water pump motor thrust bearing temperature
6. Circulating water pump discharge pressure
7. Circulating water pump bearing water pressure Low
8. Circulating water pump breaker position
9. Circulating water pump motor vibration
10. Circulating water pump bearing lubricating water supply valve position

11. Circulating water box temperature

12. Condenser discharge tunnel temperature

13. Screenwash pump breaker position

14. Screenwash pump motor overcurrent

15. Screenwash pump auto trip

16. Vacuum priming pump auto trip

17. Condenser pressure differential

18. Condenser water box vacuum break valve not fully closed

19. Circulating water pump auto trip

20. VFD alarm

21. VFD fault

The following controls and instruments are located on the liquid waste control panel:

Control switches with indicating lights for the following:

1. Screenwash pump B

2. Traveling screen and condensate demineralizer system supply valve

3. Condensate demineralizer component cooling water heat exchanger outlet isolation valve

4. (Deleted)

Local control switches with indicating lights are provided for the following:

1. Traveling water screen

2. Screenwash pump discharge valve

3. Variable Freqency Drive

Local indicators are provided for the following:

1. Screenwash pump (indicator lights)

2. Traveling screen differential level

3. Traveling screen differential water level

4. Trash rack differential level

5. Vacuum priming seal water flow

The following indicators are provided on the switchgear:

1. Breaker indicator lights

2. Circulating water pump amperage in bypass mode

3. Vacuum priming pump indicator lights

10.4.6 CONDENSATE POLISHING DEMINERALIZER SYSTEM

The condensate polishing demineralizer system (Figure 10.4 5) removes suspended and dissolved solids from the condensate stream. The condensate polishing demineralizer system is not safety related.

10.4.6.1 Design Bases

The condensate polishing system removes, from the condensate stream, impurities resulting from condenser tube leakage, primary to secondary leakage, corrosion of the feedwater-condensate system, and produces a high-quality effluent capable of meeting feedwater and steamside chemistry specifications. The condensate polishing system is capable of treating the entire flow of condensate, and is capable of maintaining condensate impurities resulting from condenser tube leakage below EPRI Action Level values for condenser leakage rates up to 1000 ml/min (approximately 0.26 gpm). The system conforms with NRC Regulatory Guide 1.56, Positions C.1 through C.5 for indirect cycle plants. [(1)]

In normal operation, the condensate polishing demineralizers produce effluent that meets the requirements specified by secondary plant water chemistry procedures.

Sufficient demineralizer redundancy allows demineralizer regeneration while the system retains its full polishing capacity. The system is also designed to meet NRC Branch Technical Positions ASB 3-1 and MEB 3-1 as related to breaks in high and moderate energy piping systems outside containment. Table 10.4-2 lists condensate polishing system design data.

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(1) Regulatory Guide 1.56 was withdrawn by the NRC (see 75 FR 7526, 2/19/10). The withdrawal of Regulatory Guide 1.56 does not alter any prior or existing licensing commitments or conditions based on its use.

10.4.6.2 System Description

The condensate polishing system consists of eight 196 cubic foot mixed bed demineralizers located in the condensate stream between the condensate pump discharge and the steam-jet air ejector units. Seven demineralizers normally handle the full condensate flow while the resin in the eighth demineralizer is being regenerated or in standby. Resin regeneration is performed manually. A normally closed bypass valve can be opened manually to route the condensate flow around the demineralizers. Demineralizers may be bypassed if demineralizer differential pressure increases to a point where demineralizer damage or excessive condensate flow restriction may occur, during plant startup, or during other plant conditions where feedwater quality can still be maintained within chemistry specifications. The resins used in the demineralizers are initially in the H^+ and OH^- forms mixed in a chemically equivalent ratio.

The condensate polishing system ion exchange resins require periodic cleaning and regeneration whenever either a demineralizer effluent quality does not meet acceptable values or the pressure drop across a resin bed is too high. The resin cleaning and/or chemical regeneration is done externally to the demineralizers.

The polisher regeneration equipment consists of a cation regeneration vessel, an anion regeneration vessel, and a resin mix and storage vessel. A lime system for regenerating the resin if the polishing system is operated in the ammonia cycle, and an ultrasonic resin cleaner are also available, but not currently used.

Resin beds to be regenerated are first transferred from the demineralizer to the cation regeneration vessel where the anion and cation resins are separated. The anion resin is then transferred to the anion regeneration vessel. The resins are chemically regenerated using sulfuric acid for cation resin and a caustic solution for anion resin. The regenerated resins are transferred to the resin mix and storage vessel for mixing and slucing back to the demineralizer vessel. Spent resin can be disposed of by sluicing from the resin mix and storage vessel through the resin transfer line to temporary storage containers. Alternatively, spent resin may also be slucied to the radioactive waste disposal system of Unit 2 See Figure 10.4-5 (3 of 5).

The design pressure of the condensate side of the condensate demineralizer system is 700 psig.

10.4.6.3 Safety Evaluation

This system is not safety related. Failure of any portion or component of this system will not damage any safety related component or system. The following design evaluation is provided to demonstrate the system capability to perform its intended function.

<u>Massive Condenser Tube Failure</u>

The system provides some degree of protection even during massive leaks, such as a complete tube failure, thus affording “reaction” time to take corrective action or initiate a unit shutdown.

In order to prevent resin breakthrough into the steam generators, the condensate polishing demineralizer (CND) system design has the following features:

1. Each condensate polishing demineralizer, 3CND-DEMN1A through H, is provided with an underdrain system consisting of a rubber lined steel header and stainless steel laterals capable of retaining whole and partial resin beads.

2. Resin strainers (traps), 3CND-STR1A through H, are used on the outlet of each demineralizer prior to manifolding at the common effluent header. The strainer baskets are designed to retain all particles larger than 50 mesh if demineralizer underdrain failure occurs. Procurement specifications ensure less than 0.5 percent of new resin is smaller than 50 mesh.

   Each strainer is provided with a pressure differential indicating switch, 3CND-PDIS 35A through H, which actuates an alarm and an indicating light when the strainer has become fouled by resin and should be cleaned by backflushing.

3. The broken, disintegrated, and worn beads and resin fines (finer than 50 mesh) formed by attrition are removed from the resin along with accumulated crud during air/water scrub and backwash steps in the cation regeneration tank (3CND-TK1). Resin fines can also be removed by the ultrasonic resin cleaner (3CND-URC1) if used.

10.4.6.4 Tests and Inspection

The polisher vessels were hydrostatically tested in the assembly shop. The control system was also tested in the shop to ensure proper valve and pump operation sequences. Following installation, the system was hydrostatically tested as a complete unit.

The condensate polishing system is normally in continuous operation whenever the steam generators are being fed by main feed or condensate. If no condenser in-leakage occurs, each demineralizer is regenerated as required by resin exhaustion or increasing pressure drop. Therefore, operability of the demineralizers and the regeneration system is demonstrated on a regular basis.

System equipment is tested for leakage and proper automatic operation prior to initial startup of the unit.

10.4.6.5 Instrumentation Requirements

The conductivity of the influent condensate to the condensate demineralizers, the effluent from each demineralizer, and the condensate returning to the condensate header is measured and recorded continuously.

Impurity levels of the effluent from each demineralizer can be measured and recorded. An alarm signal is provided on the condensate polishing panel to indicate high levels.

A differential pressure transmitter is provided to monitor the differential pressure across the condensate demineralizer system. An alarm signal is provided to the condensate polishing panel and to the main control board common alarm, to indicate high differential pressure. A manual pushbutton is provided to open the normally closed bypass valve to bypass the demineralizer system.

Flow transmitters, recorders, and flow indicating totalizers are provided to monitor the throughput of each condensate demineralizer.

Continuous measurement of the waste stream for any radioactivity during disposal is provided by an element installed on a sample line which discharges back to the sump. Presence of a radionuclide concentration exceeding the guidelines established in 10 CFR 20 automatically terminates disposal to the circulating water outfall line. The applicable guidelines are those in Appendix B of 10 CFR 20. The validity of measurement by further tests and any possible need for diversion to the radwaste system are assessed by station operating personnel.

10.4.7 CONDENSATE AND FEEDWATER SYSTEMS

The condensate and feedwater systems (Figures 10.4-1 and 10.4-6) supply feedwater at the required temperature, pressure, and flow rate to the secondary sides of the steam generators.

10.4.7.1 Design Basis

The condensate and feedwater systems are designed to provide approximately 16.267 x 10^6 pounds per hour of feedwater at 443°F to the steam generators during steady state operation (i.e., at NSSS warranted power). The portion of the feedwater system from the steam generators up to the first restraint beyond the isolation valve outside containment is Safety Class 2 and is designed to Quality Group B standards as defined in Regulatory Guide 1.26. The portion of the feedwater system upstream of the first restraint beyond the isolation valve to the turbine building wall is Safety Class 3 and is designed to Quality Group C standards. The remainder of the feedwater system and the entire condensate system are non safety related and are designed to Quality Group D standards. The safety related portions of the condensate and feedwater system are designed in accordance with the seismic design criteria discussed in Section 3.7B.3. The remainder of the feedwater system and the entire condensate system are nonseismic.

Portions of the feedwater system are also designed to the following criteria:

1. General Design Criterion 2 for structures housing the system and the system itself being capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods.

2. General Design Criterion 4 for structures housing the system and the system itself being capable of withstanding the effects of external missiles and internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks.

3. General Design Criterion 44, to assure:

   a. The capability to transfer heat loads from the reactor system to a heat sink under both normal operating and accident conditions.

   b. Redundancy of components so that under accident conditions the safety function can be performed assuming a single active component failure. (This may be coincident with the loss of offsite power for certain events.)

   c. The capability to isolate components, subsystems, or piping if required so that the system safety function is maintained.

4. General Design Criterion 45 for design provisions to permit periodic inservice inspection of system components and equipment.

5. General Design Criterion 46 for design provisions to permit appropriate functional testing of the system and components to assure structural integrity and leak-tightness, operability and performance of active components, and capability of the integrated system to function as intended during normal, shutdown, and accident conditions.

6. General Design Criterion 54 for design of lines penetrating containment to provide leak detection, isolation, and containment capabilities having redundancy, reliability, and performance requirements which reflect the importance to safety of isolating the piping system. The system is also 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.

7. Regulatory Guide 1.26 for the quality group classification of safety related system components.

8. Regulatory Guide 1.29 for the seismic design classification of safety related system components.

9. Regulatory Guide 1.102 for the protection of structures, systems, and components important to safety from the effects of flooding.

10. Regulatory Guide 1.117 for the protection of structures, systems, and components important to safety from the effects of tornado missiles.

11. Branch Technical Positions ASB 3-1 and MEB 3-1 for breaks in high and moderate energy piping systems outside containment (Section 3.6).

10.4.7.2 System Description

The condensate system condenses and collects steam exhaust from the low pressure turbines and the feedwater pump turbines. Condensate is drawn from the condenser hot well (Section 10.4.1) by three vertical half capacity condensate pumps. Normally, two of the condensate pumps operate at full load (Table 10.4-3).

Upon tripping of either condensate pump, the standby condensate pump is started automatically in order to continue plant operation at full load. From this header, the entire volume of flow is directed through the condensate demineralizers (Section 10.4.6). A bypass is provided to allow operation without use of the demineralizers.

Permanent piping is installed at the condensate pump discharge to drain the condenser hotwell to the circulating water discharge tunnel to facilitate cleaning the hotwell.

From the main condensate header, a small line containing a pressure reducing valve supplies seal water to various pumps, valves, and loop seals throughout the plant.

From the main header, a portion of flow is directed through the steam jet air ejector units (Section 10.4.2) and the steam packing exhauster condenser (Section 10.4.3). Condensate flow serves as cooling water for these units. After passing through these units, the cooling water is returned to the main condensate header. A control valve is positioned in the main condensate header between the inlet to the steam jet air ejectors and the exit from the steam packing exhauster condenser. This valve is modulated to maintain flow through the steam jet air ejectors at constant at approximately 25 percent.

An additional branch from the condensate header provides condensate for the following services:

1. Turbine hood exhaust sprays, which are required to cool the turbine exhaust hoods during startup or low power operation.

2. Condenser desuperheating sprays, which are in operation whenever steam is being dumped to the condenser.

3. Condensate system recirculation, which provides adequate cooling for the steam jet air ejectors and steam packing exhauster condenser during low power levels as well as minimum flow recirculation for the condensate pumps.

4. Condensate drawoff to the condensate surge tank for excess water in the condensate system.

The main condensate header is then split into three parallel strings of low pressure feedwater heaters. The feedwater heaters (Figure 10.4-7) heat the condensate by condensing extraction steam from the turbine generator (Figure 10.4-3). The condensed steam is drained to either the next lower pressure heater or to the condenser.

Each low pressure (GED) feedwater heater string has five regenerative feedwater heaters (second through sixth on Figure 10.4-7). The second point feedwater heater receives the cascaded drains from the high pressure first point heater. The low pressure drains of the second point heater are cascaded to the third point heater and from the third point heater to the fourth point heater. The combined drains are then pumped to the condensate stream downstream of the fourth point heater by three vertical heater drain pumps. The fifth and sixth point heaters drain directly to the condenser. The fifth point heater drains via a control valve and the sixth point heater drains via a loop seal in the drain line. Cascading drains enable an optimum amount of heat to be extracted from the heater drains. With the exception of the loop sealed sixth point heater, each of the heaters has an individual emergency drain directly to the condenser in the event of a high level in the associated heater. The condensate from each heater string is collected in a suction header for the feedwater pumps. A bypass line is provided from the feedwater pump suction header to the feedwater pump discharge header allowing the steam generators to be filled and serviced by the condensate pumps during initial startup. A low pressure heater bypass is provided to allow approximately 93 percent NSSS-warranted power flow and to prevent exceeding the design duty of the operating heaters should one heater string be isolated.

Three half-sized steam generator feedwater pumps take suction from the condensate system. Two of the pumps are steam turbine-driven and are normally operating; the third is an electric motor-driven pump on standby service. The feedwater pumps discharge into a common header. Feedwater is then passed through three parallel aligned, high pressure feedwater heaters (first point heaters). The discharges of the first point heaters are collected in a common header from which four individual supply lines to the steam generators originate.

Condensed extraction steam in the first point feedwater heater shells is drained to the second point heaters. An emergency drain line is provided for each heater directly to the condenser in the event of high level in the associated heater.

A high pressure heater bypass is provided to allow approximately 93 percent NSSS-warranted power flow should one heater be isolated.

Each of the main feedwater steam generator supply lines contains a motor-operated stop valve, a flow modulating control valve, and a main feedwater isolation trip valve. A bypass line is provided around each set of main feedwater control valves and contains the main feedwater bypass level control valve. During startup, low load operations (less than approximately 25 percent NSSS power), and shutdown, feedwater is admitted to the steam generators through the bypass lines. At approximately 25 percent NSSS power, flow control to the steam generators is manually transferred from the feedwater bypass valves to the main feedwater flow modulating valves (Section 7.7.1.7).

Each steam generator feedwater pump is provided with a minimum recirculation flow control valve for protection against undue temperature rise and vibration in the pump casing at reduced pump flows.

A condensate storage tank (capacity 300,000 gallons) is provided for storage of demineralized water required by the condensate and feedwater systems. A condensate surge tank (capacity

150,000 gallons) is provided for supplying makeup requirements for the condensate and feedwater systems. Automatic electric heating is provided for both tanks to maintain a 40°F minimum water temperature. A line from the condensate surge tank to the condenser hot well supplies makeup to the condensate system upon demand. Excess water in the condensate system is returned to the condensate surge tank via the condensate pump discharge header.

The condenser hot well level is automatically controlled by normal, low, and high water level controllers during steady state and transient conditions. The normal level and low level controllers modulate valves in the condensate makeup and emergency makeup lines, respectively. The high level controller modulates a control valve in the condensate draw off line during abnormal high hot well level conditions. High and low level alarms are actuated on the main control board. Chemical feed equipment is provided to ensure proper chemistry control of feedwater and condensate systems during all modes of operation. Hydrazine and a pH control agent are provided to the condensate system inside the turbine building during normal plant operation to maintain required oxygen and pH levels. During startup and hot standby, these chemicals are provided directly to the feedwater system inside containment. Each chemical feed line inside containment contains an air-operated isolation valve which is closed during normal plant operation. The primary objective of chemical injection is to minimize corrosion of the steam generator internals. The secondary objectives are:

1. To prevent or minimize turbine deposits due to carryover from the steam generator.

2. To reduce corrosion in the steam/feedwater cycle and deposits in the steam generator.

3. To minimize or prevent scale deposits on the steam generator heat transfer surfaces and in the turbine.

4. To minimize feedwater oxygen content.

5. To minimize the potential for the formation of free caustic or acid in the steam generators.

These objectives are attained by comprehensive sampling and laboratory analyses, chemical injection at selected points, normally continuous blowdown from each steam generator, use of condensate polishers, and chemical protection of the steam generator and feedwater train internals during outages.

10.4.7.3 Safety Evaluation

During normal operation and shutdown, the condensate and feedwater systems supply feedwater to the steam generators. During accident conditions, the feedwater system is isolated from the steam generators.

During normal plant operation, a failure in the feedwater control system could lead to one of two possible events. The first event is an abnormal increase of water inventory within the steam

generator, and the second event is an abnormal decrease of water inventory within the steam generator. The abnormal increase is terminated by steam generator high level function, which reacts to cause feedwater isolation should two out of the three high level bistables indicate an abnormally large steam generator water inventory (each steam generator has three high level bistables). The abnormal decrease is terminated by the steam generator low-low water level function. Should two of four low-low water level signals be initiated in any one steam generator, reactor trip will occur and the motor-driven auxiliary feedwater pumps will automatically start. Should two of four low-low water signals be initiated by any two of the steam generators, the turbine-driven auxiliary feedwater pump will automatically start.

Feedwater isolation valves are provided to isolate the safety related portions of the feedwater system from the remainder of the feedwater and condensate systems. These valves close automatically (within 5 seconds) on receipt of a feedwater isolation signal generated by a safety injection signal, high-high water level in any steam generator, or by a reactor trip coincident with a low T_{avg}. The main feedwater flow control and bypass level control valves receive the feedwater isolation trip signal and receive power from opposite trains, therefore, providing a backup to the isolation valves.

To preclude over pressurization of the feedwater system piping due to deadheading of feedwater pumps during feedwater isolation after a reactor trip coincident with low RCS T_{avg}, the feedwater pumps trip automatically approximately 15 seconds after initiation of reactor trip signal. A bypass switch with normal and bypass positions is provided on the main control panel to facilitate a post trip manual restart of any of the FW pumps, as well as to bypass the FW pumps trip function during operation below approximately 25% power, when over pressurization is not feasible.

Check valves are provided in the safety related portion of each feedwater line leading to the steam generators to preclude the uncontrolled blowdown of more than one steam generator in the event of a feedwater line break (Section 15.2.8).

The effects and radiological consequences of condensate and feedwater system malfunctions resulting in loss of normal feedwater flow, increase in feedwater flow, or decrease in feedwater temperature are discussed in Sections 15.2.7, 15.1.2, and 15.1.1, respectively. The effects of a feedwater system line break inside or outside the containment are discussed in Section 15.2.8.

The safety related portion of the feedwater system is protected from tornadoes and tornado generated missiles by virtue of being housed in Seismic Category I structures (Section 3.3). Protection from floods is discussed in Section 3.4. Protection against the dynamic effects of high and moderate energy pipe breaks (including pipe whip) is discussed in Section 3.6. Analyses have been performed to locate pipe supports and restraints necessary to prevent a whipping pipe from adversely affecting any structures, systems, or components necessary for safe shutdown.

The condensate system and that portion of the feedwater system inside the turbine building are non-safety related. During normal operation, one condensate pump and the motor-driven feedwater pump are on standby service. If one of the operating turbine-driven feedwater pumps fails, the motor-driven feedwater pump automatically starts on low discharge header pressure. The standby condensate pump automatically starts if either of the two running condensate pumps

trip. The feedwater and condensate systems are capable of operation at 100 percent NSSS power with one condensate and one steam generator feedwater pump out of service. Any failure in the nonsafety class portion of the condensate and feedwater system has no effect on the safety of the reactor. A source of feedwater supply to the steam generator is required for decay heat removal from the reactor following a unit shutdown. In the event that the condensate and feedwater systems are not available, the auxiliary feedwater system (Section 10.4.9) provides the required emergency supply of feedwater.

Tube rupture in any feedwater heater necessitates isolation of the heater string in which the malfunctioning feedwater heater is located. Two motor-operated isolation valves are provided for each string of low pressure feedwater heaters and for each high pressure heater. If a tube break occurs in either of the feedwater heaters located in the condenser neck, the isolation valves close automatically. If a break occurs in any of the remaining feedwater heaters, the affected low pressure heater string or high pressure heater is isolated remote-manually. Bypasses are provided for both the low pressure and high pressure heater strings. These bypasses are designed to allow for approximately 93 percent NSSS-rated power flow in the event of isolation of a single heater string. The shell sides of the feedwater heaters are protected from overpressure by relief valves.

Failures in the condensate demineralizer system require isolation of the system from the condensate system. Manual isolation valves are provided, one each in the lines going to and returning from the demineralizer. A motor-operated valve is provided in the bypass line around the condensate demineralizers.

Release of radioactivity to the environment in the event of pipe rupture in the condensate or feedwater system is bounded by the release that would occur from a pipe rupture in the main steam system (Section 15.1.5).

The feedwater system piping is arranged to prevent water hammer from occurring at the steam generators. The feedwater system has been analyzed to ensure the system withstands the effects of water hammer caused by a turbine-driven feedwater pump trip or a sudden closure of the feedwater isolation valves. No hydraulic instabilities are postulated in the condensate system.

Measures will be taken as appropriate to protect personnel from any toxic effects of chemicals used for water treatment. The tanks in which these chemicals are mixed and stored are vented to the atmosphere outside the turbine building. A safety shower and eyewash are provided near the tanks for use by operating personnel in case of spillage accidents. Because the chemicals are not significantly flammable, fire protection equipment is not needed.

Chemical feed isolation valves are provided to isolate the safety related portions of the feedwater and chemical feedwater systems from the nonsafety portions. These valves are closed during normal operation and opened during startup operations. Each valve closes automatically upon receipt of a feedwater isolation trip signal.

10.4.7.4 Testing and Inspection Requirements

All piping in the condensate and feedwater systems was hydrostatically tested during construction, and all active system components such as pumps, valves, and controls were functionally tested during startup and tested periodically thereafter.

Sampling connections are provided in the condensate pump discharge header, sixth point feedwater heaters inlet, and downstream of each first point heater. Periodic samples are taken from the condenser hotwell, and the condensate surge and storage tanks. Condenser hotwell samples are tested for sodium, conductivity, and chloride. Condensate surge and storage tank samples are tested for oxygen, pH, conductivity and chloride. In addition, condensate surge tank samples are tested for total gamma activity and condensate storage tank samples are tested for sodium.

Provisions have been made to permit inservice inspection of Safety Class 2 and 3 portions of the feedwater system as required by ASME XI (Section 6.6). Code Class 2 high energy fluid system components in designated break exclusion areas (BEA) are accessible for augmented inservice inspection.

Testing of the feedwater containment isolation valves is discussed in Section 7.1.2.5.

10.4.7.5 Instrumentation Requirements

Condensate System

Control switches and indicator lights are on the main control board for operation of the three condensate pumps. Normally, two pumps are running; the standby pump starts automatically when either one of the running pumps is tripped. Each pump motor is provided with an ammeter on the main control board and an ammeter and indicator lights at the switchgear.

The following annunciators are on the main control board:

1. Condensate pump flow Low.

2. Low pressure heater bypass valve not fully open.

3. Condensate pump auto trip/motor overcurrent (common).

4. Control power not available.

5. Motor stator winding temperature High (each pump motor).

6. Condenser sealwater pressure High.

7. Condenser sealwater pressure Low.

The following parameters are monitored by the plant computer:

1. Condensate pump auto trip.
2. Condensate pump motor overcurrent.
3. Condensate pump motor upper sleeve bearing temperature.
4. Condensate pump motor lower sleeve bearing temperature.
5. Condensate pump motor thrust bearing temperature.
6. Condensate pump motor stator winding temperature.
7. Turbine exhaust hood temperature.
8. Condenser hot well water temperature.
9. Condensate discharge header temperature.
10. Condensate discharge header pressure.
11. Condensate header flow.
12. Sixth point heater inlet temperature.
13. Fifth point heater inlet temperature.
14. Fifth point heater outlet temperature.
15. Fourth point heater inlet temperature.
16. Fourth point heater outlet temperature.
17. Third point heater inlet temperature.
18. Third point heater outlet temperature.
19. Second point heater inlet temperature.
20. Second point heater outlet temperature.

Indicators on the main control board monitor the following parameters:

1. Condensate discharge header temperature.

2. Condensate discharge header pressure.

3. Condenser pump motor amperage.

4. Condensate header flow.

5. Turbine exhaust hood spray bypass valve position.

6. Hot well level.

The condenser hot well level is automatically controlled by normal, low, and high level controllers. The normal level and low level controllers modulate control valves in the condensate normal makeup and emergency makeup lines, respectively. The high level controller modulates a control valve in the condensate drawoff line during abnormally high hot well level conditions. High and low level alarms are actuated on the main control board.

Control switches and position indicator lights are on the main control board for the condensate pump discharge valves. Throttling control is utilized for the condensate pump discharge valves.

The condensate demineralizer mixed bed bypass valve has control switches and position indicator lights on the main control board and on the condensate demineralizer panel. A REMOTE/LOCAL control selector switch is located on the main control board. Throttling control is used and a valve position indicator is located on the condensate demineralizer panel. Differential pressure across the condensate demineralizer is indicated on the main control board.

A flow indicating controller located on the auxiliary condensate panel is used to modulate the condensate minimum flow recirculation control valve. Valve position indicator lights are located on the main control board. Condensate pump low flow is alarmed in the control room.

Control switches and position indicator lights are provided on the main control board for the low pressure feedwater heater isolation valves. The heater string isolation valves are closed automatically by high-high level in the associated strings fifth or sixth point heaters.

The low pressure heater bypass valve has a control switch and valve position indicator lights on the main control board. The valve is opened automatically by high-high level in any fifth or sixth point low pressure feedwater heater. An annunciator is alarmed in the control room if the bypass valve fails to open after an open signal has been initiated.

The plant computer monitors each low pressure feedwater heater inlet and outlet temperature.

Feedwater System

A control switch and indicator lights are located on the main control board for the motor-driven feedwater pump. The pump starts automatically on low feedwater pump discharge header pressure. A feedwater pump motor ammeter is provided on the main control board and at the switchgear. Indicator lights are also located at the switchgear.

Annunciators are alarmed on the main control board when any of the following conditions exists:

1. Feedwater pump discharge pressure Low.
2. Motor-driven steam generator feedwater pump overcurrent/auto trip.
3. Feedwater isolation signal.
4. Feedwater isolation signal bypassed.
5. Feedwater pump discharge pressure High.
6. Feedwater pump suction pressure Low.
7. Feedwater pumps trip on reactor trip bypassed.

The following parameters are monitored by the plant computer:

1. Feedwater pump motor overcurrent.
2. Feedwater pump motor auto trip.
3. Feedwater pump motor breaker position.
4. Feedwater isolation trip signal.
5. Feedwater pump suction flow.
6. Feedwater pump suction temperature.
7. Feedwater pump discharge temperature.
8. Feedwater isolation signal bypassed.
9. Feedwater pumps trip on reactor trip bypassed.

A speed controller automatically controls speed of the turbine-driven feed pumps. Automatic/manual control selectors are located on the main control board. Inputs to the speed controller are steam flow, main steam header pressure, and feedwater pumps discharge header pressure.

Motor-operated valves are utilized as feedwater pump discharge isolation valves. Control switches and valve position indicator lights are provided on the main control board.

Isolation valves for the first point feedwater heaters, isolation valves for the main feedwater control valves, and the first point feedwater heater bypass valve are motor-operated valves.

Control switches and valve position indicator lights are provided on the main control board for manual operation.

The main feedwater isolation trip valves isolate the feedwater line as close to the containment structure wall as possible upon receipt of a feedwater isolation signal. Control switches with valve position indicators are provided on the main control board for manual operation.

Air-operated containment isolation valves are provided on each chemical feed line. The valves close automatically on receipt of a feedwater isolation signal. Control switches and valve position indicator lights are located on the main control board for manual operation.

Engineered safety features status lights for each chemical feed line containment isolation valve and for each main feedwater stop valve are provided on the main control board.

Water level in the steam generators is controlled by feedwater control valves. A separate three-element feedwater control system is provided for each steam generator. Feedwater flow is controlled automatically above approximately 25 percent load by a three-element controller using steam generator water level, steam flow, and feedwater flow to control the feedwater flow control valve for each steam generator. The feedwater flow control valve is pneumatically operated and is of the fail closed design. The feedwater control valves close automatically on receipt of a feedwater isolation signal. Valve position indicator lights and engineered safety features status lights for feedwater flow control valves are provided on the main control board.

Each feedwater flow control valve has an inlet isolation valve and a bypass line containing a steam generator level control valve. A level controller modulates the feedwater bypass control valve to automatically control steam generator level when plant load is less than approximately 25 percent. This bypass level control valve closes on receipt of a feedwater isolation signal. Automatic/manual controls are provided on the main control board. Valve position indicator lights and engineered safety features status lights for each level control valve are provided on the main control board.

The feedwater isolation trip signal is initiated when any of the following conditions exist:

1. Any steam generator High-High level.

2. Safety injection signal (SIS).

The feedwater isolation trip valve signal is initiated when any of the following conditions exist:

1. Any steam generator High-High level

2. Safety injection signal (SIS)

3. Reactor tripped coincident with a low T_{avg} signal present

The feedwater isolation trip signal causes the main feedpumps, feedpump turbines, and main turbine to trip, while the feedwater isolation trip valve signal causes the feedwater isolation and control valves and the chemical feed steam generator valves to trip. The feedwater pumps will also trip approximately 15 seconds after a reactor trip to preclude system over pressurization due to pump deadheading.

A minimum recirculation flow control valve is provided for each steam generator feedwater pump. A flow controller on the auxiliary condensate panel with flow indication and automatic/manual features is utilized to maintain recirculation flow at a predetermined setpoint. A control switch and valve position indicator lights are provided on the main control board for each valve. Low feedwater pump suction flow is alarmed in the control room.

Indicators are provided on the main control board to monitor the following parameters:

1. First point feedwater heater outlet header pressure
2. Steam generator level program
3. Steam generator level
4. Main steam header pressure
5. Feedwater pumps discharge header pressure

Recorders are provided on the main control board for the following:

1. Steam generator level
2. Feedwater flow

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The steam generator blowdown system is shown on Figure 10.3-1.

10.4.8.1 Design Basis

The steam generator blowdown system is used in conjunction with the condensate demineralizer, chemical addition, and sample systems to control the chemical composition of the steam generator shell side water within specified limits (Section 5.4.2). During extended outage periods, the steam generators are placed in wet layup. Wet layup connections are provided on each steam generator and in each steam generator blowdown train and wet layup recirculation skids are installed in each steam generator cubicle to facilitate chemical mixing and recirculation of the steam generator inventory. Temporary hose, which is stored outside containment during plant operation, is used to connect the wet layup skids and the wet layup connections.

The steam generator blowdown system is monitored continuously for radiation in the secondary side of the steam generator. It has the capability of diverting the blowdown liquid (after isolation and substantial cooldown of a steam generator) to the radioactive liquid waste system in the event of a high radiation signal resulting from a steam generator tube leak. Main condenser inleakage is discussed in Section 10.4.1.

The steam generator blowdown system isolation valves automatically close whenever a sequenced safeguard signal (CDA, SIS, LOP), an auxiliary feedwater pump auto start signal (any steam generator 2-out-of-4 low-low level), a reactor plant sampling system radiation high signal, or an AMSAC actuation signal is present. An auto close signal can be reset at the main control board and the valves reopened manually.

The normal steam generator blowdown system flow is typically 22,800 lbm/hr per steam generator.

The design pressure and temperature of the steam generator blowdown system from the steam generators up to and including the manually operated system isolation valves at the inlet of the blowdown tank (V950) and the inlet of the steam generator drain pump (V975) are 1,185 psig and 600°F (same as the design pressure and temperature of the shell side of the steam generators). Downstream of V950, the system has a design pressure of 75 psig and a design temperature of 360°F.

Downstream of V975 the system has a design pressure of 75 psig and a design temperature of 150°F. The steam generator wet layup skids and hose have a design pressure of 100 psig and a design temperature of 250°F.

The portion of the steam generator blowdown system up to and including the containment isolation valves is Seismic Category I and designated Safety Class 2. All other piping and equipment in the steam generator blowdown system is nonnuclear safety class (NNS) and is designed to ANSI B31.1. The steam generator wet layup skids are nonnuclear safety class (NNS). However, they are designed and supported in such a manner that any failure will not preclude operation of safety-related equipment.

10.4.8.2 System Description

The four steam generator blowdown lines, one from each steam generator, are routed through the containment to a common area where they penetrate the containment wall in the main steam valve building. A containment isolation valve is located in each blowdown line and the blowdown valves are located downstream of these isolation valves. The blowdown lines are joined in a common header downstream of the blowdown valves; the header runs to the steam generator blowdown tank. Blowdown tank pressure is maintained at 60 to 75 psig, slightly above the normal operating pressure of the fourth point feedwater heater shells, by use of a pressure valve in the steam line connected to the fourth point heaters, and by the blowdown valves through a controller on the main board. Liquid in the tank flows to the condenser hotwell during closed cycle operation and to the circulating water discharge tunnel during open cycle blowdown. The blowdown tank is protected against overpressurization by a relief valve.

Open cycle blowdown is employed during startup and hot standby to aid in removing ionics and solids from the steam generators. During open cycle blowdown, steam from the steam generator blowdown flash tank is vented to atmosphere and condensate is discharged to the circulating water discharge tunnel.

Drain lines are connected from the four steam generator blowdown lines downstream of the containment isolation valves. These lines are joined in a common header that enters the steam generator drain pump. The steam generator drain pump discharge lines are connected to the condensate demineralizer mixed bed waste neutralization sumps and the radioactive liquid waste system high level waste drain tanks. A hose connection is provided to direct the Steam Generator Drain Pump discharge to the Circulating Water Discharge Tunnel, after sampling. Drain connections on the steam generator drain the shell side water into the radioactive liquid waste system via the containment sump.

During extended outage periods the steam generators will be placed in wet lay-up using temporary hose connections off the steam generator blowdown system. The hoses will be connected to four permanently installed wet lay-up skids located inside the steam generator cubicles at elevation 28 feet 6 inches Each skid contains a pump, chemical addition tank, cartridge filter, cation exchanger demineralizer associated piping and valves, sampling connections, pressure and temperature gauges, and a combination starter. These components are sized to provide sufficient recirculation flow and chemical addition capability to maintain steam generator water chemistry within recommended limits.

10.4.8.3 Safety Evaluation

Steam Generator Blowdown flash tank can be drained to the circulating water discharge tunnel or the main condenser, while it is being vented to the atmosphere, main condenser, or the fourth point feedwater heater shells. Actual flow path being used will be determined by operations in accordance with chemistry and regulatory requirements. A primary to secondary leak in the steam generator which could contaminate the steam generator blowdown system and the secondary side of the plant is detected by the Steam Generator Blowdown Sample Monitor which is part of the Reactor Plant Sampling System (Section 9.3.2). The affected steam generator could be isolated and subsequently drained after a substantial temperature reduction by the steam generator drain pump to the radioactive liquid waste system.

10.4.8.4 Testing and Inspection

The steam generator blowdown containment isolation valves and the upstream piping to the steam generators are Safety Class 2. Access is provided so that the Safety Class 2 piping and valves can be inservice inspected in accordance with ASME XI.

Piping within the jurisdiction of ANSI B31.1.0 is inspected and tested in accordance with Paragraphs 136 and 137, respectively, of that code.

10.4.8.5 Instrumentation Requirements

The steam generator blowdown isolation valves are provided with control switches and valve position indicator lights on the main control board. The steam generator blowdown system isolation valves automatically close whenever a sequenced safeguard signal (CDA, SIS, LOP), an auxiliary feedwater pump auto start signal (any steam generator 2/4 low-low level), a reactor plant sampling system radiation high signal, a condenser air removal radiation high signal, or an AMSAC actuation signal is present. An auto close signal can be reset at the main control board and the valves reopened manually. Engineered safety features status lights are provided on the main control board for each valve and the plant computer monitors OPEN and CLOSED positions for each steam generator blowdown isolation valve.

A steam generator blowdown outlet flow control valve is located downstream from each steam generator blowdown isolation valve. A manual control station for each valve is provided on the main control board. The valves are closed automatically by a condenser low vacuum signal or a steam generator blowdown tank high pressure signal.

The steam generator drain pump is provided with a control switch and indicator lights on the main control board for manual operation.

Controllers with indication and auto/manual features are located on the main control board to maintain level and pressure for the steam generator blowdown tank at predetermined set points.

The steam generator blowdown tank steam to condenser isolation valve is provided with a control switch and valve position indicator lights on the main control board for manual operation.

Control switches and valve position indicator lights are provided on the main control board for the fourth point extraction steam inlet valves. The valves close automatically when the associated fourth point heater level is high.

Annunciators are alarmed on the main control board when the following conditions exist:

Steam generator blowdown tank level high
Steam generator blowdown tank pressure high
Steam generator blowdown isolation valve reset

Steam generator blowdown tank pressure and steam generator blowdown flow are monitored by the plant computer.

10.4.9 AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater system is shown on Figure 10.4-6.

10.4.9.1 Design Basis

The auxiliary feedwater system provides a supply of high-pressure feedwater to the secondary side of the steam generators for reactor coolant system (RCS) heat removal following a loss of normal feedwater. It also provides a cooling source in the event of a small break loss-of-coolant accident (LOCA). Furthermore, the system is used in the event of a main steam line break, feedwater line break, loss of power, or low-low steam generator water level conditions. Under loss of offsite power conditions, the auxiliary feedwater system maintains the plant at a standby condition. Under loss of all AC power (station blackout), the turbine-driven auxiliary feedwater pump remains capable of auto or manual start due to the DC powered steam supply valves (Section 7.3.1.1.5).

The auxiliary feedwater system operates during startup and hot standby to maintain water level in the steam generators.

The auxiliary feedwater system also operates in conjunction with the main steam system to cool the RCS to hot shutdown conditions during normal cooldown and safety grade cold shutdown operations. See Section 5.4.7 for a description of normal and safety grade cold shutdown.

The auxiliary feedwater system maintains the water level in the steam generators at the appropriate level to minimize temperature increases in the RCS which also minimizes the release of primary coolant through the pressurizer relief valves.

The auxiliary feedwater system from the main feedwater system up to and including the isolation valves just outside containment is Safety Class 2 (Section 3.2).

The demineralizer water storage tank (DWST) fill line from the water treating system, overflow line, and the heater circulating pump and piping are designed to nonnuclear safety (NNS), (Section 3.2). The safety class portions of the auxiliary feedwater system are seismically designed as discussed in Section 3.7.B.3.

Two half-capacity, motor-driven pumps and one full capacity turbine-driven pump are provided to ensure an adequate supply of auxiliary feedwater following an accident coincident with a single active failure.

The turbine-driven pump is rated at 1,150 gpm at 2,975 foot total head (TDH) while the motor-driven pumps are each rated at 575 gpm at 2,975 foot TDH. The turbine-driven pump or the pair of motor-driven pumps each have sufficient capacity for sensible and decay heat removal.

The turbine-driven pump and controls are powered completely independent of the motor-driven auxiliary feedwater pumps and controls.

All redundant components are physically separated from each other by an arrangement of concrete barriers designed to preclude coincident damage to equipment in the event of a postulated pipe rupture, equipment failure, or missile generation.

The auxiliary feedwater system is designed in accordance with the following criteria.

1. General Design Criterion 2, for structures housing the system and the system itself being capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods.

2. General Design Criterion 4, with respect to structures housing the system and the system itself being capable of withstanding the effects of external missiles and internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks.

3. General Design Criterion 5, for shared systems and components important to safety being capable to perform required safety functions.

4. General Design Criterion 19, for the design capability of system instrumentation and controls for prompt hot shutdown of the reactor and potential capability for subsequent cold shutdown.

5. General Design Criterion 34, to ensure:

    a. The capability of the auxiliary feedwater system to sufficiently transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

    b. Suitable redundancy in components, features, interconnections, leak detection, and isolation capabilities is provided to assure, under assumption of a single failure, the continued safety function regardless of the loss of either onsite, offsite, or the generating capability of both power systems.

6. General Design Criterion 44, to ensure:

    a. The capability to transfer heat loads from the reactor system to a heat sink under both normal operating and accident conditions.

    b. Redundancy of components so that under accident conditions the safety function can be performed assuming a single active component failure (This may be coincident with the loss of offsite power for certain events).

    c. The capability to isolate components, subsystems, or piping, if required, so that the system safety function is maintained.

7. General Design Criterion 45, for design provisions to permit periodic inservice inspection of system components and equipment.

8. General Design Criterion 46, for design provisions to permit appropriate functional testing of the system and components to ensure structural integrity and leaktightness, operability and performance of active components, and capability of the integrated system to function as intended during normal, shutdown, and accident conditions.

9. Regulatory Guide 1.26, for the quality group classification of system components (Section 3.2).

10. Regulatory Guide 1.29, for seismic design classification of system components (Section 3.2).

11. Regulatory Guide 1.62, for design provisions made for manual initiation of each protective action.

12. Regulatory Guide 1.102, for the protection of structures, systems, and components important to safety from the effects of Flooding.

13. Regulatory Guide 1.117, for the protection of structures, systems, and components important to safety from the effects of tornado missiles.

14. Branch Technical Positions APCSB 3-1 and MEB 3-1, for breaks in high and moderate energy piping systems outside containment.

15. Branch Technical Position ASB 10-1, for auxiliary feedwater pump drive and power supply diversity.

16. Branch Technical Position RSB 5-1 for safety grade cold shutdown.

17. Selected auxiliary feedwater system minimum flow rates:

    a. Design:

       The auxiliary feedwater system is designed to supply a minimum auxiliary feedwater flow in accordance with Figure 10.4-10 to four steam generators even with the occurrence of a single failure following any Condition II event; e.g., loss of normal feedwater, loss of offsite power, refer to Chapter 15.0 for details.

       The auxiliary feedwater system is designed to supply a minimum auxiliary feedwater flow in accordance with Figure 10.4-11 to three effective steam generators even with the occurrence of a single failure following any Condition III or IV event; e.g., secondary-side rupture, small break loss-of-coolant accident, or cooldown following steam generator tube rupture, refer to Section 15.0 for details.

b. Reliability

A better estimate loss of normal feedwater analysis is performed to support the probabilistic risk assessment reliability analysis of the auxiliary feedwater system. For the purpose of this reliability analysis, the system will supply a minimum auxiliary feedwater flow in accordance with Figure 10.4-12 to two intact steam generators even with the failure of two out of three auxiliary feedwater pumps. This capacity is provided to protect against multiple failures as well as to provide diversity between power sources.

18. The DWST is designed to provide sufficient water for the above transients and:

a. hot standby condition for 7 hours with steam discharge to atmosphere concurrent with a total loss of offsite power;

b. with an additional 6-hour cooldown period sufficient to reduce reactor coolant hot leg temperature to 350°F to allow residual heat removal system operation; and

c. in the event of a feedwater line break, an allowance for 30 minutes of spillage before operator action to isolate the depressurized steam generator.

The DWST is also designed to provide sufficient water for safety grade cold shutdown in accordance with BTP RSB 5-1.

19. NRC NUREG-0611 recommendation GL-3 which requires at least one auxiliary feedwater system pump and its associated flow path and essential instrumentation to automatically initiate auxiliary feedwater flow and be capable of being independent of any alternating current power source for at least two hours.

20. Appendix R to 10 CFR 50 fire protection program requirements for mechanical components and instrumentation required for cold shutdown.

21. NRC Generic Letter 80-020 dated March 10, 1980, concerning the "Actions Required from Operating License Applicants of Nuclear Steam Supply Systems Designed by Westinghouse and Combustion Engineering Resulting from the NRC Bulletins and Orders Task Force Review Regarding the Three Mile Island Unit 2 Accident."

22. Appendix A to 10 CFR 50 General Design Criterion 57, for design provisions to ensure that each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation.

10.4.9.2 System Description

The system is located in both the ESF and the containment buildings, which are both Seismic Category I structures. The DWST is located in the yard with piping that is run underground to the ESF building.

The auxiliary feedwater system consists of two motor-driven auxiliary feedwater pumps, one turbine-driven auxiliary feedwater pump and the associated piping and valves necessary to connect the DWST to the pump suctions, and the pump discharges to the feedwater system. The DWST is provided with a heater cycle consisting of a recirculating pump and electric heater which automatically maintains the water temperature at or above 40°F. The auxiliary feedwater system is shown on Figure 10.4-6.

Two half size motor-driven auxiliary feedwater pumps and one full size turbine-driven auxiliary feedwater pump are provided. Sufficient auxiliary feedwater for plant cooldown can be supplied by either the turbine-driven pump or the pair of motor-driven pumps. For the better estimate loss of normal feedwater analysis performed to support the reliability analysis, a single motor-driven auxiliary feedwater pump is also capable of supplying an auxiliary feedwater flow in accordance with Figure 10.4-12 to two intact steam generators. This capacity is provided to protect against multiple failures as well as to provide diversity between power sources.

The steam generator auxiliary feedwater pumps are used as an emergency source of feedwater supply to the steam generators. The pumps are required to ensure safe shutdown in the event of loss of power or functions as an Engineered Safeguards System to remove core decay heat. The pumps are on standby service during normal plant operation.

The motor-driven steam generator auxiliary feedwater pumps start automatically whenever any of the following conditions occur:

1. Loss of power or (LOP)

2. Safety injection signal (SIS).

3. Containment depressurization actuation signal (CDA).

4. Two-of-four low-low water level signals in any one steam generator.

5. AMSAC Actuation Signal (from AMSAC system).

The motor-driven (Train A) steam generator auxiliary feedwater pump is isolated from AUTO start and sequencer signals when in LOCAL control to facilitate safe shutdown from a remote shutdown location following a fire as described in Section 6.2.11 of the Fire Protection Evaluation Report.

The motor-driven auxiliary feedwater pumps take suction from the condensate storage tank to maintain steam generator water levels during startup and hot standby.

The turbine-driven steam generator auxiliary feedwater pump starts automatically given the two of four Low-Low water level signals in any two of four steam generators, or an AMSAC auto-start signal, or loss of emergency 125 VDC power.

The steam generator auxiliary feedwater pumps start automatically or can be started manually from the main control board. In addition, the turbine driven pump can be started manually from the auxiliary shutdown panel by opening the turbine pump steam supply valves (Section 7.4.3.1). The motor driven pumps can be manually started from their switchgear.

The auxiliary feedwater pump turbine drive receives steam from the main steam system (Section 10.3.2) piping through the steam generator auxiliary feedwater pump turbine steam supply header. The source of steam is not interrupted by a loss of AC power (station blackout). When the turbine driven pump is started, it is initially supplied with 990 psia steam. As the reactor cools and the steam pressure decreases below approximately 615 psia, the turbine drive speed decreases. However, sufficient pump capacity is available until the steam pressure to the turbine inlet decreases to 120 psia. Auxiliary feedwater flow for further cooling, if required, can be provided by one motor-driven auxiliary feedwater pump. When reactor coolant temperature decreases to 350°F, at which condition the residual heat removal system is typically placed into service (Section 5.4.7), the auxiliary feedwater system is manually secured.

Motive steam is provided to the turbine driven auxiliary feedwater (TDAFW) pump from A, B, and D steam generators (3RCS*SG1A/B/D). A three inch supply line comes off the main steam line from each of these steam generators and tie into a common steam supply header to the TDAFW pump. Each of the three steam supply lines is provided with a normally closed, Fail Open, air operated valve which isolates the auxiliary feedwater turbine from the main steam system during normal operation (3MSS*AOV31A/B/D). Each branch line is also provided with a drain strainer/oriface (venturi) (3DTM-STR2A/B/D and 3DTM-RO70A/B/D), to remove any steam which has condensed in the piping, upstream of the closed AOV. To further eliminate sources of condensation in the TDAFW Pump steam supply header, a condensate collection standpipe is provided in the common steam supply header, downstream of the isolation valves. This standpipe is provided to collect steam which has leaked through the closed isolation valves and condensed in the down stream piping.

Each motor-driven steam generator auxiliary feedwater pump receives power from a separate redundant emergency electrical bus.

Each AFW pump is provided with a continuously open recirculation line back to the DWST. Each recirculation line is furnished with a restriction orifice (3FWA*RO24A/B/C) which is sized to bypass a safe minimum quantity of water. The turbine-driven AFW pump recirculation line has a 90 gpm nominal hydraulic design value. Each motor-driven AFW pump recirculation line has a 45 gpm nominal hydraulic design value. The continuously open recirculation flow path design feature eliminates the need for an active instrumentation and control system to open the recirculation path on a low pump flow condition. Thus, providing a reliable recirculation system that ensures minimum pump flow requirements are satisfied. Cooling water, required for pump and turbine bearing oil cooling, is supplied from the first stage casing of each pump. This provides a guaranteed source of cooling water under all conditions.

During safety related operation, each auxiliary feedwater pump takes suction through a separate supply line directly from the DWST. The DWST, tank capacity of 360,000 gallons, has sufficient capacity to satisfy the design basis of the auxiliary feedwater system. The total tank capacity includes unusable volume necessary to prevent vortexing at the auxiliary feedwater pump suction nozzles. Makeup is provided to the DWST from the water treating system (Section 9.2.3).

An additional source of water is provided to each auxiliary feedwater pump suction by the condensate storage tank (Section 9.2.6). This source is not safety related. The normally closed air-operated valves connecting the condensate storage tank and each motor-driven auxiliary feedwater pump suction are closed automatically on receipt of an SIS, CDA, auxiliary feedwater pump AUTO start (any steam generator 2-out-of-4 low-low level), AMSAC, or LOP signal. The turbine-driven pump is provided with an administratively-controlled locked closed valve.

A domestic water system connection is provided for DWST replenishment. A removable spool piece must be installed to use this design feature. This spool piece is provided, in lieu of permanent piping, to preclude inadvertent domestic water introduction into the steam generators. A 2.5 inch diameter fire hose connection fitting for use at the domestic water spool piece location is also available for installation to support DWST replenishment from the fire water system.

A service water system to auxiliary feedwater pump suction cross-tie design feature is provided. However, this cross-tie design feature is only used as an option of last resort due to seawater's deleterious impact on steam generator tube integrity. Before the auxiliary feedwater pumps can take suction from the service water system, spool pieces must be installed. These spool pieces are provided, in lieu of permanent piping, to preclude inadvertent seawater introduction into the steam generators.

Feedwater from the steam generator auxiliary feedwater pumps is pumped to each steam generator through normally open control valves which may be throttled during auxiliary feedwater pump operation during startup, shutdown, and standby. Flow is monitored in each line connecting to the feedwater system. Each control valve is manually adjusted from the control room as dictated by the steam generator water level and auxiliary feedwater flow rate. The control valves can also be manually adjusted from the auxiliary shutdown panel. In the event of a loss of power, these valves remain open.

Auxiliary feedwater flow to the steam generators is limited by flow venturis located in each auxiliary feedwater line. These venturis are sized to cavitate in order to maintain the minimum required flows to the intact steam generators and to prevent runout flow to a depressurized steam generator.

The auxiliary feedwater is discharged to the steam generators through a connection in each main feedwater line inside the containment structure and downstream of the main feedwater check valves. This will prevent loss of auxiliary feedwater, should a main feedwater line rupture upstream of the main feedwater check valve. The design parameters for the auxiliary feedwater pumps are listed in Table 10.4-4.

The TDAFW pump sub-system contains suction and discharge connections that facilitate portable diesel engine driven AFW pump deployment and DWST replenishment. These connections are defense-in-depth design features that are available for coping with an extended loss of AC power (ELAP) event. The location and interconnections of these BDB AFW FLEX suction and discharge connections are shown on Figure 10.4.6, Sheet 2.

10.4.9.3 Safety Evaluation

Each motor-driven steam generator auxiliary feedwater pump receives power from one of the emergency AC buses. One pump is available at all times in the event of the loss of one emergency bus. The turbine-driven pump is sufficiently sized to be used for residual heat removal as long as adequate steam is available. The turbine-driven pump receives control power from DC sources only. An ample supply of steam for the turbine-driven steam generator auxiliary feedwater pump is available, provided at least one steam generator and its associated main steam loop from the steam generator to the main steam isolation trip valve are intact. The reactor coolant temperature and pressure will be reduced to a level where the residual heat removal system may be used before the main steam pressure is no longer adequate to operate the turbine-driven pump. The two motor-driven pumps operating together are sized to provide sufficient auxiliary feedwater to cool the plant until the residual heat removal system can be initiated.

Each MDAFW pump flowpath is independent from the other and feeds two steam generators. Two intact steam generators are required for decay heat removal. The TDAFW pump is redundant to the two MDAFW pumps in that it feeds all four steam generators. Controls are provided on the auxiliary shutdown panel or the Emergency Switchgear to ensure that the reactor may be brought to a hot standby condition, should the control room become uninhabitable.

The amount of water provided in the DWST is sufficient to hold the unit at hot standby for up to 7 hours and to provide a cooldown period of 6 hours, concurrent with a total loss of offsite power, at which time the residual heat removal system will be initiated. This amount of water is also sufficient for safety grade cold shutdown operations.

The amount of flow to any steam generator is limited by cavitating venturis located in the auxiliary feedwater line to each steam generator. These elements are passive and are sized to cavitate at a flow which will allow sufficient cooling water to each steam generator. Because cavitation occurs, the flow will remain at the venturi's rated flow regardless of the downstream pressure. Therefore, these elements will limit flow to a depressurized steam generator thus preventing the pumps from operating near runout.

Preventing runout flow provides a more suitable condition for the pumps to remain operable for extended periods.

If the DWST level cannot be maintained above the required usable volume, the reactor will be placed in a shutdown condition. The leak will be located, isolated, and repaired. All pumps, valves, and piping will be operable, and the DWST will contain the minimum required usable volume prior to taking the reactor critical.

The tornado and missile protected DWST meets Seismic Category I requirements and is available under all accident conditions.

The condensate storage tank provides a non-safety grade backup source of water for the auxiliary feedwater pumps. DWST design features include non-safety grade water treating system and domestic water system piping connections that may be used for DWST replenishment, if required. A 2.5 inch diameter fire hose connection fitting is also available for installation to support DWST replenishment via the fire water system. A safety grade service water system to auxiliary feedwater pump suction cross-tie design feature is available. However, this is only used as an option of last resort due to seawater's deleterious impact on steam generator tube integrity.

On receipt of a sequenced safeguard signal auxiliary feedwater pump AUTO start signal (any steam generator 2-out-of-4 low-low level), or AMSAC, the two motor-driven steam generator auxiliary feedwater pumps start and supply cooling water to the steam generators through parallel flow paths to remove the core sensible and decay heat. Each of the motor driven pump flowpaths is independent from the other and feeds two steam generators. Two intact steam generators are required for heat decay removal. The turbine driven AFW pump is redundant to the two motor driven AFW pumps in that it feeds all four steam generators.

The motor-driven auxiliary feedwater pumps may be in normal use to support steam generator inventory maintenance during startup, shutdown, and hot standby. Normal auxiliary feedwater use occurs only at below 10% rated thermal power. When the auxiliary feedwater system is in normal use, plant operators may partially or fully close control valves 3FWA*HV31A/B/C/D to control steam generator water levels. These control valves do not receive an auto-open signal given an auxiliary feedwater auto-initiation signal. In this case, manual operator action is credited to open these control valves and to support auxiliary feedwater system operability. This manual action can be accomplished in the control room. For a reactor trip at low thermal power levels, the lower RCS decay heat and high steam generators thermal capacitance (heat removal capability) provides an adequate time for operators to manually open these control valves, if required. During normal auxiliary feedwater system use, the turbine driven auxiliary pump feedwater control valves (3FWA*HV32A/B/C/D and 3FWA*HV36A/B/C/D) are maintained fully open. The motor-driven auxiliary feedwater pumps may be aligned to take suction from the nonsafety grade condensate storage tank during these evolutions. Pump suction automatically switches to the DWST, including isolation from the condensate storage tank, in the event to an SIS, LOP, CDA, two of four low-low water level in any one steam generator, or AMSAC signal.

Assuming a single failure, either the two motor-driven, or the turbine-driven auxiliary feedwater pump are of sufficient capacity to remove the sensible and decay heat from the reactor core. The system supplies enough water to the steam generators to facilitate a safe shutdown condition and maintain it until the residual heat removal system is actuated. Above 10% power, system also delivers sufficient auxiliary feedwater to the steam generators, starting at 60 and 90 seconds after signal receipt for the motor driven and turbine driven auxiliary feedwater pumps, respectively, to prevent lifting of the pressurizer safety valves.

A reliability evaluation was performed for the auxiliary feedwater system to determine the potential for system failure. The method of evaluation was similar to that described in

NUREG-0611, Appendix III. This analysis included the calculation of the systems unavailability using fault tree logic and an investigation of the potential for system failures under various loss of feedwater transient conditions. A detailed failure mode and effect analysis of the system electrical controls was also completed in accordance with Regulatory Guide 1.70, Paragraph 7.3.2.

The analysis of the auxiliary feedwater system showed the reliability to be in accordance with criteria defined in SRP Section 10.4.9. Implementation of 10 CFR 50.65 ensures continuous monitoring of auxiliary feedwater system reliability and compliance with the SRP criteria.

The investigation did not reveal any significant potential sources for common cause failures. It should be noted that the fault tree analysis considered various multiple failures, including operational errors, which might result in a common cause single failure. Physical separation was also considered as a source of common cause failures. The most likely components were the pumps. Each pump is located in a separate projectile-protected cubicle. The air-conditioning units and MCCs for the turbine-pump steam supply valves are located in separated cubicles on the floor above the pumps. The portions of the system required for safety meet Seismic Category I design requirements. Redundant electrical trains are provided for pump and valve controls.

10.4.9.4 Inspection and Testing Requirements

All piping in the auxiliary feedwater system was hydrostatically tested during construction, and all active system components, such as pumps, valves, and controls, are functionally tested periodically.

The steam generator auxiliary feedwater pumps, their drives, and the pump discharge valves are tested at intervals indicated by Technical Specifications. Each of the three pumps will be tested individually. An independent check of the system valve lineup will be performed after each test prior to restoring the system to operational status. An incorrect valve lineup will be displayed on the ESF status panel. Steam is admitted to the turbine drive, and the motor drives are energized during these tests. Flow is established by recirculating auxiliary feedwater to the DWST. Following the completion of the test, the auxiliary feedwater pumps are shut off, and the motor-operated shutoff valves leading to the main feedwater lines are opened. Pump discharge pressure is indicated on the main control board for each auxiliary feedwater pump.

All system components are tested and inspected in accordance with the applicable codes.

Periodic sampling of the water in the DWST is provided in the tank heating cycle. The samples are tested for oxygen content and pH.

Inservice inspection of Safety Class 2 and 3 portions of the auxiliary feedwater system are performed as required by the ASME Code, Section XI (Section 6.6).

10.4.9.5 Instrumentation Requirements

The DWST is provided with redundant level indication on the main control board and on the auxiliary shutdown panel. High, low, and low-low (DWST) level alarms are provided on the main control board.

A DWST heater and heater pump are utilized to maintain water temperature above freezing. Control switches and indicator lights are provided locally and on the turbine plant sample sink panel. The circulating pump starts automatically when DWST water temperature is 35°F or the circulating pump suction temperature is 50°F. The tank heater operates to maintain the tank contents above 40°F. DWST low temperature (less than 35°F) is alarmed on the main control board.

Isolation valves in the DWST circulating pump suction line are provided with control switches and valve position indicator lights on the main control board. The valves are closed automatically by a safety injection signal or loss of power signal. Engineered safety features status lights on the main control board indicate when the valves are closed. The open and closed positions are monitored by the plant computer.

Control switches and indicator lights are provided on the main control board and at the switchgear for each auxiliary feedwater motor driven pump. Remote local control selector switches are provided at the switchgear; an alarm is activated on the main control board when LOCAL control is selected. Pump motor ammeters are provided on the main control board and at the switchgear. Engineered safety feature status lights indicate on the main control board when an auxiliary feed pump motor is started. The auxiliary feed pump motors are started automatically by two out of four low-low levels in any steam generator, by an AMSAC actuation signal or by an engineered safety features actuation signal. This signal is initiated whenever an SIS, CDA, or LOP signal is present. The ESF actuation signal (Section 7.3) is sequenced on when an LOP signal exists. The Train A motor-driven auxiliary feedwater pump is isolated from the AUTO start signal when it is in LOCAL control.

Control switches and valve position indicator lights are provided on the main control board and on the auxiliary shutdown panel (ASP) for the turbine-driven auxiliary feedwater pump steam supply valves. LOCAL/REMOTE control transfer switches are located on the transfer switch panel (TSP); an alarm is activated on the main control board when LOCAL control is selected. Open and close valve positions are monitored by the plant computer. The steam supply valves are opened automatically by two out of four low-low levels in two of four steam generators or by an AMSAC actuation signal. Upon loss of 125V DC, these valves fail open.

The auxiliary feedwater pump turbine steam supply nonreturn valves have control switches and valve position indicator lights on the main control board for manual operation.

The auxiliary feedwater isolation valves are provided with control switches and valve position indicator lights on the main control board and on the ASP. REMOTE/LOCAL control transfer switches are located on the TSP; an alarm is activated on the main control board when local control is selected.

The motor driven auxiliary feedwater pump alternate suction valve for each pump has a control switch with valve position indicating lights for manual operation on the main control board.

The following instrumentation and controls are located on the main control board:

Indicators
Each auxiliary feed pump's suction pressure
Each auxiliary feed pump's discharge pressure
Auxiliary feedwater flow to each steam generator
DWST fill line flow
DWST level (2)
Auxiliary feed pump turbine speed
Turbine-driven auxiliary feedwater pump steam pressure
Ammeter for the motor-driven auxiliary feedwater pump
Auxiliary feedwater control valve demand signal
Annunciators
Auxiliary feed pump 1A suction pressure low
Auxiliary feed pump 1B suction pressure low
Auxiliary feed pump 2 (TDAFWP) suction pressure low
Auxiliary feed pump 1A lube oil pressure Low
Auxiliary feed pump 1B lube oil pressure Low
Auxiliary feed pump 1A motor winding temperature High
Auxiliary feed pump 1B motor winding temperature High
Control for auxiliary feedwater isolation valve in local control
DWST level High
DWST level Low
DWST level Low-Low
DWST temperature Low
Auxiliary feedwater system bypassed (TRAIN A)
Auxiliary feedwater pump motor AUTO TRIP/OVERCURRENT
Auxiliary feedwater system bypassed (TRAIN B)
Auxiliary feed pump turbine speed in remote control
Motor-driven auxiliary feedwater pump local control
Control Switches
Motor-driven auxiliary feedwater START/STOP
Auxiliary feedwater control valves OPEN/CLOSE
Auxiliary feedwater pump steam supply valve OPEN/CLOSE
Controller
Speed control for auxiliary feed pump turbine

The following indicators are located on the auxiliary shutdown panel:

Auxiliary feedwater flow to each steam generator (indicators for steam generators 1A and 1D are provided with umbilical type connections to isolate the normal source device and connect an alternate source device to facilitate safe shutdown from a remote shutdown location following a fire as described in Section 6.2.11 of the Fire Protection Evaluation Report).

DWST level (2)

The following parameters are monitored by the plant computer:

Auxiliary feedwater pump suction pressure
Auxiliary feedwater pump motor breaker position
Auxiliary feedwater pump motor winding temperature
Auxiliary feedwater pump motor bearing temperature
Auxiliary feedwater control valve open and closed positions
Auxiliary feedwater pump discharge pressure
Auxiliary feedwater pump motor overcurrent
Auxiliary feedwater pump motor auto trip
Auxiliary feedwater pump discharge temperature High
Auxiliary feedwater pump ventilation system bypassed
Auxiliary feed pump motor control circuit open
Auxiliary feed pump motor control switch in Pull-To-Lock position
Auxiliary feedwater system bypassed (TRAIN A)
Turbine-driven auxiliary feedwater pump steam pressure
Turbine-driven auxiliary feedwater pump trip valve
Turbine steam supply valve open and closed positions
Auxiliary turbine-driven feed pump bypassed (TRAIN B)
Auxiliary feedwater flow to each steam generator

10.4.10 AUXILIARY STEAM AND ASSOCIATED SYSTEMS

The Unit 3 auxiliary steam system is designed to supply steam to and carry condensate from various heating and processing equipment associated with both Unit 2 and Unit 3 during normal plant operations. The Unit 3 auxiliary steam and associated systems are shown on Figure 10.4-9.

10.4.10.1 Design Basis

The Unit 3 auxiliary steam and associated systems (auxiliary condensate, auxiliary boiler feedwater and condensate, auxiliary boiler blowdown and auxiliary boiler steam) are non-safety related systems and are designed in accordance with the ANSI Code for Pressure Piping, ANSI

B31.1. The Unit 3 auxiliary steam system provides a steam supply to the Unit 2 auxiliary steam system via an existing crosstie between the Units. A description of the Unit 2 auxiliary steam system is presented in the MP-2 FSAR.

The Unit 3 auxiliary boiler steam and auxiliary steam systems are designed to supply steam to the heating and processing equipment listed below:

Auxiliary boiler deaerator (6 psig)
Regenerant evaporator reboiler (50 psig) (Removed from Service)
Boron evaporator reboiler (100 psig)
Degasifier feed preheater (150 psig)
Waste evaporator reboiler (100 psig)
Steam to water heat exchangers (plant heating) (150 psig)
Boric acid batch tank (15 psig)
Caustic dilution water heater (150 psig)
Containment vacuum ejector (150 psig)
Steam jet air ejector units (150 psig)
Turbine gland seal steam system (150 psig)
Main feed pump turbine test (150 psig)
Auxiliary feed pump turbine test (150 psig)
Primary grade water system (150 psig)
Unit 2 auxiliary steam system (50 psig)

The auxiliary condensate system associated with the Unit 3 auxiliary steam system is designed to return the condensed steam used by some of this equipment to the condensate system if the auxiliary boilers are not operating, or to the auxiliary boiler deaerator if the auxiliary boilers are operating.

The auxiliary boiler feedwater and condensate system provides condensate from the auxiliary condensate system and condensate storage tank to the auxiliary boilers for the generation of auxiliary steam when main steam is not available during plant startup, shutdown, or extended outages.

During normal plant operations when main steam is available and the auxiliary boilers are not in use, the auxiliary feedwater and condensate system collects the auxiliary condensate and pumps it to the condensate storage tank.

10.4.10.2 System Description

The auxiliary steam system is supplied by the main steam system (Section 10.3) through a pressure reducing valve, when the unit is in operation, and by the auxiliary boilers at all other times.

Unit 3 auxiliary steam supply to the Unit 2 auxiliary steam system and condensate return, is accommodated for via a crosstie between the Units. Because the Unit 3 auxiliary steam system operates at 150 psig and the Unit 2 auxiliary steam system operates at 50 psig a pressure reducing valve station, including isolation and relief valves are installed.

The pressure reducing valve station consists of two pressure reducing valves installed in parallel and supplied with upstream and downstream isolation valves. The isolation valves are located at the crosstie between Unit 3 auxiliary steam system supply to Unit 2. The pressure reducing valve station is located in the Condensate Polishing facility in line 3-ASS-008-15-4 downstream of isolation valve 2-ASS-3. This pressure reducing valve station regulates Unit 3 auxiliary steam system mass flow to Unit 2. The pressure reducing valve station is comprised of a 2 inch pressure reducing valve, four inch pressure reducing valve, isolation valves, pressure sensing line, and a dual operated controller. This configuration allows the two inch valve to regulate auxiliary steam system mass flow from between 0 and 8,999 lb/hr as long as the downstream pressure sensing line indicates an operating pressure of 50 psig or higher. When the downstream operating pressure falls below 50 psig, the four inch pressure valve will modulate to allow up to the additional required 35,682 lb/hr auxiliary mass flow required for Unit 2 use.

A safety relief valve located downstream of the pressure reducing valve station provides downstream pressure protection for Unit 2 system piping and connected equipment.

The condensate from the degasifier feed preheater, the boron evaporator reboiler, and the waste evaporator reboiler flow through their own conductivity analyzer and a three-way valve. In case of a leak in any of these heat exchangers, its associated conductivity analyzer will detect a high conductivity in the condensate, secure steam to the unit, and then divert the condensate coming from the unit via the three-way valve to a contaminated sump, thereby preventing possible contamination of the auxiliary condensate/auxiliary steam systems. Under normal conditions, the condensate from these units flows to the auxiliary condensate flash tank of the auxiliary condensate system where a portion of it flashes to produce additional low pressure (15 psig) steam for use as needed in the boric acid batch tank. That portion of the fluid entering the auxiliary condensate flash tank which does not flash, plus condensate from the boric acid batch tank jacket, is collected in the auxiliary condensate tank. As a further precaution, if the condensate is indicated as being radioactive by the radiation monitor located in the condensate discharge line of the auxiliary condensate flash tank, the condensate is diverted via a three-way valve to the auxiliary building sump. From there, it is pumped to the radioactive liquid waste system for further processing. During normal operation, the condensate collected in the auxiliary condensate tank is pumped by one of two, 100 percent capacity auxiliary condensate pumps to the condensate surge tank in the condensate system. When the auxiliary boiler is operating, this auxiliary condensate is pumped to the auxiliary boiler deaerator.

In addition to condensate return line from the Unit 2 auxiliary feedwater surge tank is routed to the Unit 3 auxiliary boiler deaerator, when the Unit 3 auxiliary boilers are supplying auxiliary steam, or to the Unit 3 condensate surge tank, when Unit 3 main steam is supplying auxiliary steam.

The condensate from the steam to water heat exchangers, and the caustic dilution water heater is collected in the auxiliary boiler condensate receiver of the auxiliary boiler feedwater and condensate system.

Blowdown from the auxiliary boilers flows to the auxiliary boiler blowdown tank. The auxiliary boiler room floor drains are pumped forward to the auxiliary boiler blowdown tank. That portion of the blowdown which flashes into steam passes through the auxiliary boiler blowdown vent condenser. Noncondensable gases are vented to the atmosphere from the vent condenser, and the condensate is drained back to the auxiliary boiler blowdown tank. The vent and drain from the auxiliary boiler blowdown tank is pumped to the condensate demineralizer system, downstream of the etched disc filter. The fluid is then discharged to the circulating water system.

When main steam is not available and the auxiliary boilers are being used, system water level is controlled in the auxiliary boiler deaerator. On a high deaerator water level, water is bled from the auxiliary boiler feedwater pumps discharge to the condensate surge tank. On a low deaerator water level, water is pumped from the condensate surge tank via the auxiliary boiler condensate makeup pumps to the deaerator.

10.4.10.3 Safety Evaluation

Plant process steam is a significant Unit 3 requirement during normal and shutdown operation. Unit 3 auxiliary steam is supplied to Unit 2 from the Unit 3 auxiliary boilers or the Unit 3 main steam system. The Unit 3 auxiliary boilers are each rated for 60,000 lb/hr of auxiliary steam. The State of Connecticut Department of Environmental Protection air permit limits the auxiliary boiler fuel consumption rate, which in turn limits the operating capacity of each auxiliary boiler to approximately 53,333 lb/hr steam flow. The Unit 3 auxiliary steam system or Unit 3 main steam system is capable of supplying all of the Unit 2 and Unit 3 steam use requirements as well as the steam needs for the site's fire water storage tanks freeze protection during winter conditions (with plant heating) and during summer conditions (without plant heating). Temporary electric heating has been installed while the Auxiliary Steam supply is unavailable to the Fire Water tanks.

A description of the modes of operation which are available to allow Unit 3 to satisfy auxiliary steam demands include the following.

1. Unit 3 auxiliary boilers operating only.

2. Parallel operation allowing for the Unit 3 main steam and Unit 3 auxiliary boilers to operate.

3. Unit 3 main steam operating only.

In order to prevent a hostile environment from an auxiliary steam pipe break (high temperature and pressure) in the auxiliary building from damaging equipment, two quick-acting, air-operated isolation valves are located in the auxiliary steam lines in the turbine building as close as possible to the penetration into the auxiliary building. These valves are actuated by a temperature monitoring system located throughout the auxiliary building.

10.4.10.4 Inspection and Testing Requirements

After installation of the auxiliary steam and its associated systems, all equipment and devices are subjected to performance tests to demonstrate proper operation of the component. Visual inspection is conducted at regular intervals and following system maintenance to confirm normal operation of the system.

10.4.10.5 Instrumentation Requirements

Auxiliary steam supplied from the main steam system is maintained at 150 psig by a pressure control valve modulated by a pressure indicating controller. The controller has an AUTO/MANUAL control selection on the main control board. High and low auxiliary steam pressures are alarmed on the main control board.

The steam jet air ejector isolation valves have control switches and valve position indicator lights on the main control board. The steam jet air ejector isolation valves close automatically on receipt of a loss of power (LOP) signal. The plant computer monitors the close position of each isolation valve.

The auxiliary condensate flash tank is continuously monitored by a process radiation monitor (Section 11.5). Control valves supplying auxiliary steam to the degasifier feed preheater, the boron evaporator reboiler, and the waste evaporator reboiler are tripped closed on receipt of a high conductivity signal.

A three-way air operated valve is located in the condensate line from the condensate flash tank to the auxiliary condensate tank. Condensate is diverted to the auxiliary building sump upon receipt of a high radiation signal from the process radiation monitor installed upstream of the divert valve.

Upon receipt of a high conductivity signal, the three-way air operated valves divert condensate from the waste evaporator reboiler to reactor plant aerated drains; condensate from the boron evaporator reboiler and from the degasifier feed preheater is diverted to the auxiliary building sump.

A local level indicating controller and level valve automatically maintain water level in the auxiliary condensate flash tank at a predetermined level.

Control switches and indicator lights on the auxiliary condensate panel are provided for the auxiliary condensate pumps. A LEAD/FOLLOW switch selects the lead and follow auxiliary condensate pumps. The pumps are started and stopped at appropriate levels by level switches on the auxiliary condensate tank. High and low auxiliary condensate tank levels are alarmed in the control room.

The auxiliary condensate pumps discharge valve opens automatically when either auxiliary condensate pump is started and closes when both pumps are stopped. High condensate

conductivity at any sample point is alarmed in the control room and at the local panel for the associated equipment.

10.4.11 REFERENCES FOR SECTION 10.4

TABLE 10.4–1 CIRCULATING WATER AND ASSOCIATED SYSTEMS DESIGN AND PERFORMANCE CHARACTERISTICS

System	Design and Performance Characteristics
Circulating Water System	Six wet pit vertical circulating water pumps each deliver a flow of 152,000 gpm at a TDH of 27 feet. All six pumps are normally in operation.
Traveling Screen Wash and Disposal System	Two wet pit vertical screenwash pumps each deliver a flow of 4,000 gpm at a TDH of 235 feet. One pump is normally in operation when the traveling water screens are operating.
Vacuum Priming System	Two horizontal, liquid ring, centrifugal station vacuum priming pumps each remove an air volume of 1,675 cfm at a vacuum of 26 inches Hg. Two horizontal, liquid ring, centrifugal yard vacuum priming pumps each remove an air volume of 540 cfm at a vacuum of 10 inches Hg. One station pump and one yard pump are normally in operation when the circulating water system is operating.

TABLE 10.4–2 DESIGN DATA CONDENSATE POLISHING SYSTEM

Number of Vessels	8 (7 normally operating)
Design Flow, total (gpm)	19,775
Design Flow (gpm/unit)	2,825
Design Pressure (psig)	700
Design Temperature (°F)	175
Demineralizer Type	Mixed Bed
Cation Resin Volume (cubic feet/unit)	Approximately 80
Anion Resin Volume (cubic feet /unit)	Approximately 120

TABLE 10.4–3 CONDENSATE AND FEEDWATER SYSTEM EQUIPMENT DESIGN PARAMETERS

CONDENSATE PUMPS		
Design Parameter:		
Capacity at design rating (gpm)		10,890
Minimum flow requirements (gpm):		
Intermittent		2,700
Continuous		6,000
Pump efficiency at design rating (%)		85.5
Required NPSH at design rating (ft)		20.5
TDH at design rating (ft)		1,215
Bhp at design rating (hp)		3,907
Shutoff head (ft)		1,590
Material:		
Discharge column	ASTM A-515 Gr. 65, 70, and A-36	
Suction barrel	ASTM A-515 Gr. 65, 70, and A-36	
First stage impeller	ASTM A-351 Gr. CF-8M	
STEAM GENERATOR FEEDWATER PUMPS		
Capacity at design rating (gpm)		19,865
Minimum continuous flow requirements (gpm):		5,000
Pump efficiency at design rating (%)		85
Required NPSH at design rating (feet)		
If original OEM impeller installed		255
If Ingersoll-Dresser Pump replacement impeller installed		275
TDH at design rating (feet)		2,050
Bhp at design rating (hp)		10,672
Shutoff head (feet)		2,850
Material:		
Outer casing and head flange	ASTM A-105-70	
	ASTM A-296, Gr. CA-6NM	

TABLE 10.4–3 CONDENSATE AND FEEDWATER SYSTEM EQUIPMENT DESIGN PARAMETERS

Impeller		
If original OEM impeller installed	ASTM A-296, Gr. CA-6NM	
If Ingersoll-Dresser Pump replacement impeller installed	ASTM A-487, Gr. CA-6NM	

TABLE 10.4–4 EQUIPMENT DESIGN PARAMETERS

Motor-Driven Auxiliary Feedwater Pump	
Safety class	3
Seismic class	Category 1
Design flow, including recirculation (gpm)	575
Rated total head (ft)	2,975
NPSH required at rated flow (ft)	20
Shutoff head at rated flow (ft)	3,475
Minimum required recirculation (gpm) *	45
Efficiency at design point (percent)	76.0
Required Bhp at rated flow	568
Design speed (rpm)	3,560
Pump design	Horizontal, split-casing centrifugal pump, 10 stage
Casing material	ASME SA-216, WCB
Impeller material	ASTM A743 GR. CA6NM
Suction and discharge nozzle material	ASME SA-216, WCB
Weight (pump, base, driver)	9,920 lb
Turbine-Driven Auxiliary Feedwater Pump	
Safety class	3
Seismic class	Category I
Design flow including recirculation (gpm)	1,150
Rated total head (ft)	2,975
NPSH required at rated flow (ft)	22
Minimum required recirculation (gpm) *	90
Efficiency at design point (percent)	78.0
Required Bhp at rated flow	1,108

TABLE 10.4–4 EQUIPMENT DESIGN PARAMETERS

Design speed (rpm)	4,400
Pump design	Horizontal, centrifugal pump, 7 stage
Casing material	ASME SA-216, WCB
Impeller material	ASTM A743 GR. CA6NM
Suction and discharge nozzle material	ASME SA-216, WCB
Weight (pump, base, driver)	10,160 lb
Auxiliary Feedpump Motors	
Synchronized speed (rpm)	3,560
Horsepower	600
Motor electrical requirements (V / Hz / phase)	4,000 / 60 / 3
Service factor	1.0
Auxiliary Feedpump Turbine	
Rated speed (rpm)	4,400
Potential maximum hp rating	1,400
Rated horsepower (at 1,195 psia, saturated turbine inlet conditions)	1,108
Throttle flow (at 1,195 psia, sat)	64,300 lb/hr

* Nominal hydraulic design value for the minimum flow recirculation line which discharges back to DWST.

TABLE 10.4–4 EQUIPMENT DESIGN PARAMETERS

Motor-Driven Auxiliary Feedwater Pump	
Safety class	3
Seismic class	Category 1
Design flow, including recirculation (gpm)	575
Rated total head (ft)	2,975
NPSH required at rated flow (ft)	20
Shutoff head at rated flow (ft)	3,475
Minimum required recirculation (gpm) *	45
Efficiency at design point (percent)	76.0
Required Bhp at rated flow	568
Design speed (rpm)	3,560
Pump design	Horizontal, split-casing centrifugal pump, 10 stage
Casing material	ASME SA-216, WCB
Impeller material	ASTM A743 GR. CA6NM
Suction and discharge nozzle material	ASME SA-216, WCB
Weight (pump, base, driver)	9,920 lb
Turbine-Driven Auxiliary Feedwater Pump	
Safety class	3
Seismic class	Category I
Design flow including recirculation (gpm)	1,150
Rated total head (ft)	2,975
NPSH required at rated flow (ft)	22
Minimum required recirculation (gpm) *	90
Efficiency at design point (percent)	78.0
Required Bhp at rated flow	1,108

TABLE 10.4–4 EQUIPMENT DESIGN PARAMETERS

Design speed (rpm)	4,400
Pump design	Horizontal, centrifugal pump, 7 stage
Casing material	ASME SA-216, WCB
Impeller material	ASTM A743 GR. CA6NM
Suction and discharge nozzle material	ASME SA-216, WCB
Weight (pump, base, driver)	10,160 lb
Auxiliary Feedpump Motors	
Synchronized speed (rpm)	3,560
Horsepower	600
Motor electrical requirements (V / Hz / phase)	4,000 / 60 / 3
Service factor	1.0
Auxiliary Feedpump Turbine	
Rated speed (rpm)	4,400
Potential maximum hp rating	1,400
Rated horsepower (at 1,195 psia, saturated turbine inlet conditions)	1,108
Throttle flow (at 1,195 psia, sat)	64,300 lb/hr

* Nominal hydraulic design value for the minimum flow recirculation line which discharges back to DWST.

TABLE 10.4–6 CONDENSER: PHYSICAL CHARACTERISTICS AND PERFORMANCE REQUIREMENTS (1)

Number of condenser tubes	42,978
Condenser tube material	Titanium (ASTM B-338 Gr. 2)
Heat transfer area - ft^2	503,304
Overall condenser dimension - feet	40 feet-0 inches (tube length)
Number of passes	1
Hotwell capacity - gal	83,350
Minimum heat transfer - Btu/lb-stm	979
Normal steam flow - lb/hr	8,376,175
Normal cooling water temperature, °F	Range: 33-80
Maximum cooling water temperature, °F	Range: 33-80
Normal exhaust steam temperature, °F	
a. With no turbine bypass flow	97.8
b. With maximum turbine bypass flow	129.2

(1) Performance characteristics based on 55.5°F CWS.

TABLE 10.4–7 DELETED BY PKG FSC MP3-UCR-2010-012

FIGURE 10.4-1 (SHEETS 1-3) P&ID CONDENSATE SYSTEM

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-2 (SHEETS 1-2) P&ID CONDENSER AIR REMOVAL SYSTEM AND WATERBOX PRIMING

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-3 (SHEETS 1-2) P&ID EXTRACTION STEAM AND TURBINE GENERATOR GLAND SEAL AND EXHAUST

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-4 (SHEETS 1-2) P&ID CIRCULATING WATER SYSTEM

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-5 (SHEETS 1-5) P&ID CONDENSATE DEMINERALIZER - MIXED BED

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-6 (SHEETS 1-4) P&ID FEEDWATER SYSTEM

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-7 (SHEETS 1-3) P&ID FEEDWATER HEATER AND MAIN STEAM REHEAT VENTS AND DRAINS

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.4-9 (SHEETS 1-3) P&ID AUXILIARY STEAM, FEEDWATER AND CONDENSATE

The figure indicated above represents an engineering controlled drawing that is Incorporated by Reference in the MPS-3 FSAR. Refer to the List of Effective Figures for the related drawing number and the controlled plant drawing for the latest revision.

FIGURE 10.1–1 FUNDAMENTAL DIAGRAM

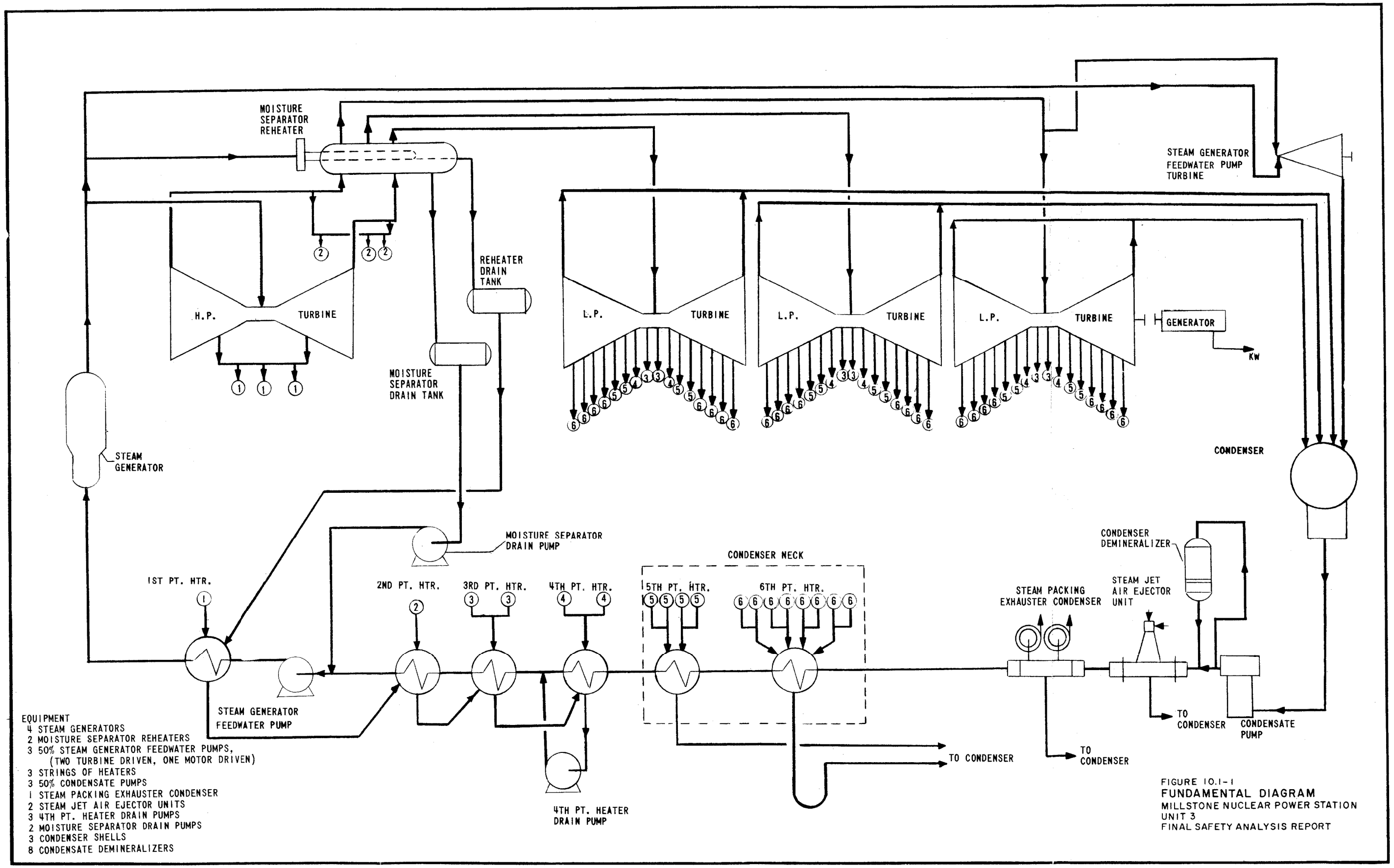


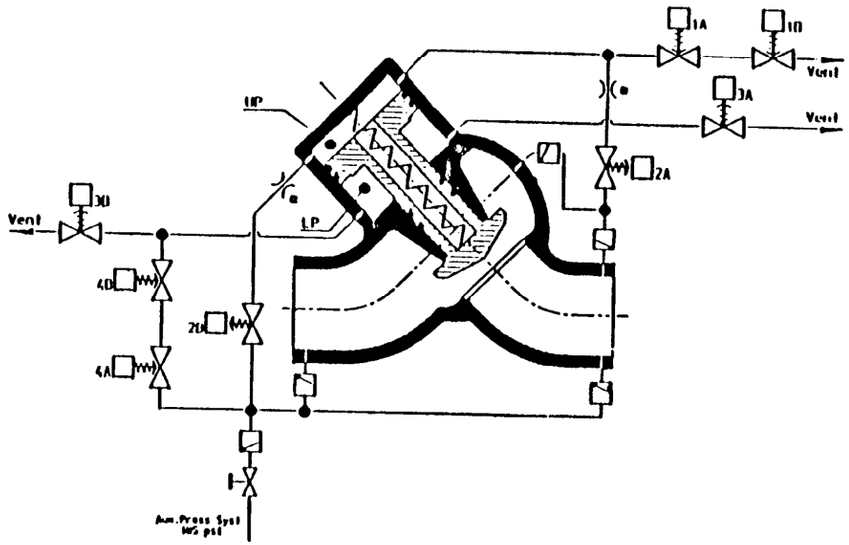
FIGURE 10.1–3 DELETED BY PKG FSC 03-MP3-027

FIGURE 10.3–3 SHEET 1(A) DELETED BY PKG FSC 98-MP3-126

FIGURE 10.3 - 4 MAIN STEAM ISOLATION VALVE

Solenoids operation requirements at given MSIV mode:

Position	Mode of operation	Remarks	UP=Upper piston chamber				LP=Lower piston chamber			
			MGV type and train				MGV type and train			
			1A	2A	1B	2B	3A	4A	3B	4B
I	MSIV open (Normal Operation)	No pressure in UP or LP	E	E	E	E	D	D	D	D
II*	MSIV partial stroke (Normal Operation) Step 1	Pressure in LP	E	E	E	E	E	E	E	E
	Step 2	Pressure in UP (time delay)	D	D	D	D	E	E	E	E
	(Return to Pos.I) Step 3	PSE open signal (unclosed)	E	E	E	E	D	D	D	D
III*	MSIV quick closing (Accident Condition)	Pressure in UP	D	D	D	D	D	D	D	D
IV*	MSIV keep closed	Pressure source Upstream or Downstream of MSIV	D	D	D	D	D	D	D	D
V*	MSIV keep closed (Indef.time, no ext.leakage)	Pressure source Upstream only of MSIV	D	D	D	D	E	E	E	E
VI*	MSIV keep open (Const. down)	Pressure in LP (Aux.)	E	E	E	E	E	E	E	E
VII*	MSIV keep open (Const. down)	Pressure in LP with Po	E	E	E	E	E	E	E	E
Energized = E			open after	closed no	open after	closed no	closed no	open after	closed no	open after
De-energized = D			closed no	open after	closed no	open after	open after	closed no	open after	closed no



Legend:

▨ = Actuation of corresponding solenoids of train A or B
1) = After Position I has been performed
2) = After Position III has been performed
3) MSS ——.——.——
MSIS No.:(2PA,B,C,D)——2PA
Solenoid MGV No.:(1 to 4)——1A
Electrical Train : (A or B)——

FIGURE 10.4–10 MINIMUM AUXILIARY FEEDWATER FLOW TO FOUR STEAM GENERATORS LOSS OF NORMAL FEEDWATER EVENT

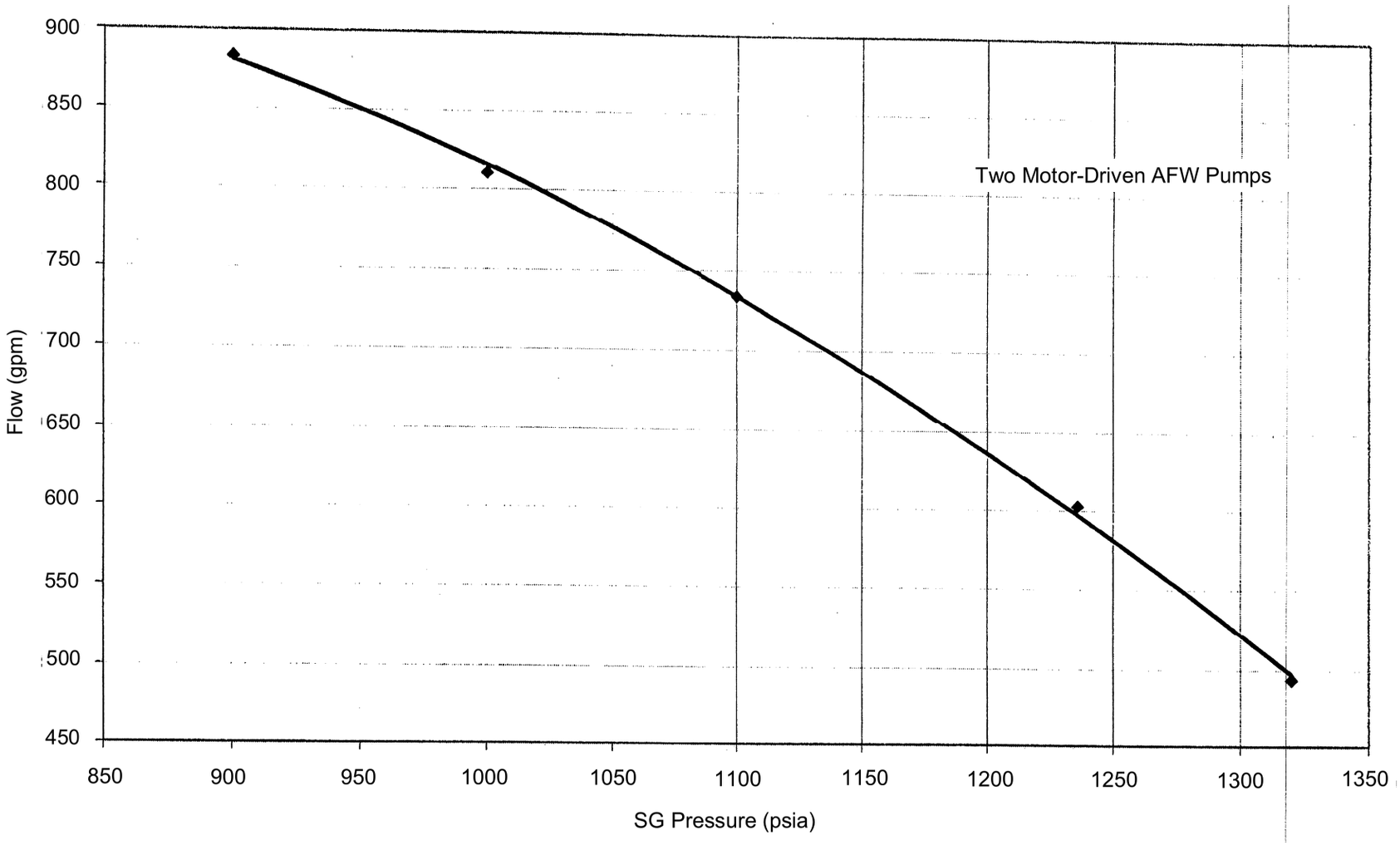


FIGURE 10.4 - 11 MINIMUM AUXILIARY FEEDWATER FLOW TO THREE EFFECTIVE STEAM GENERATORS FEEDWATER LINE BREAK EVENT

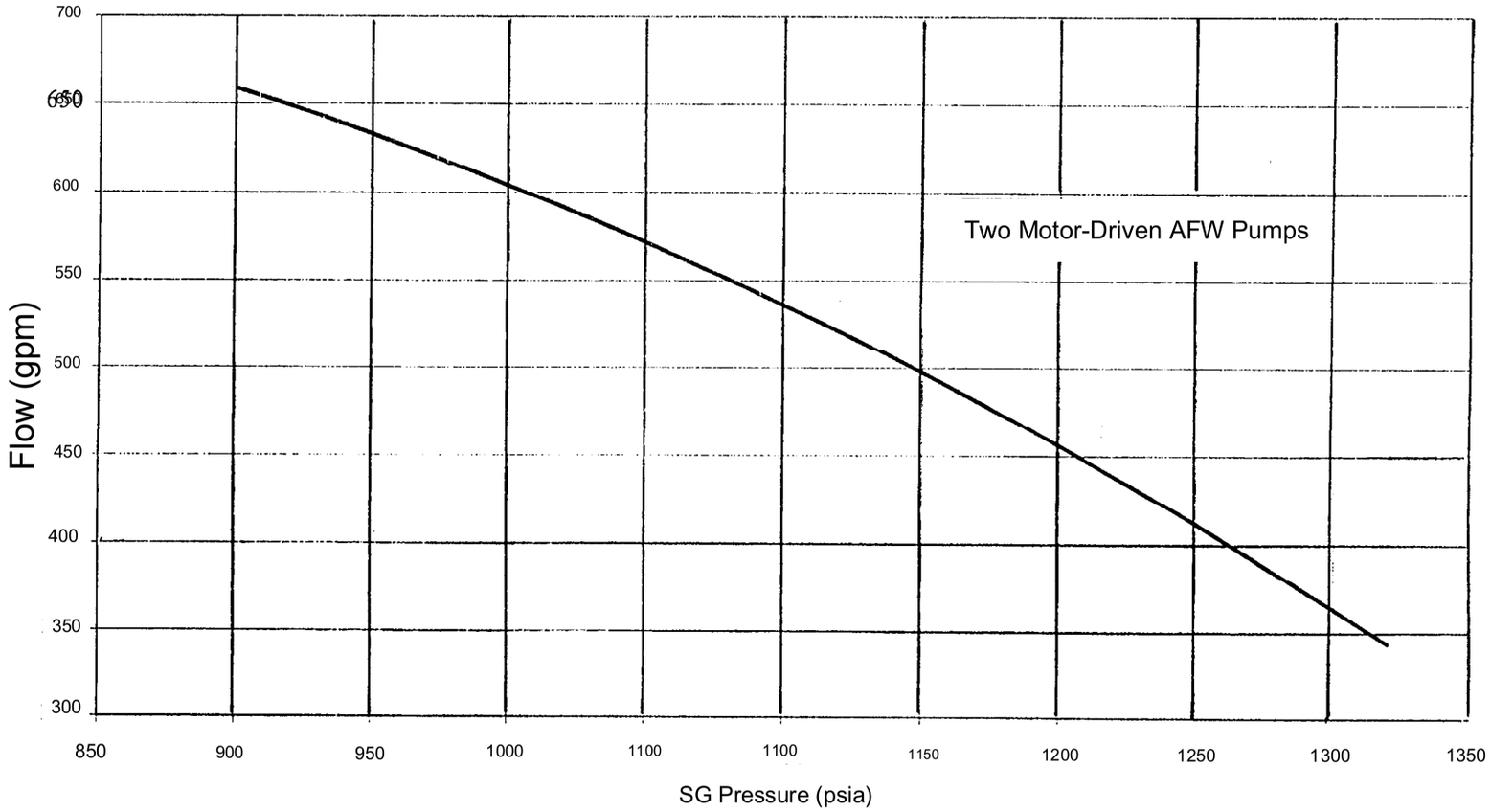
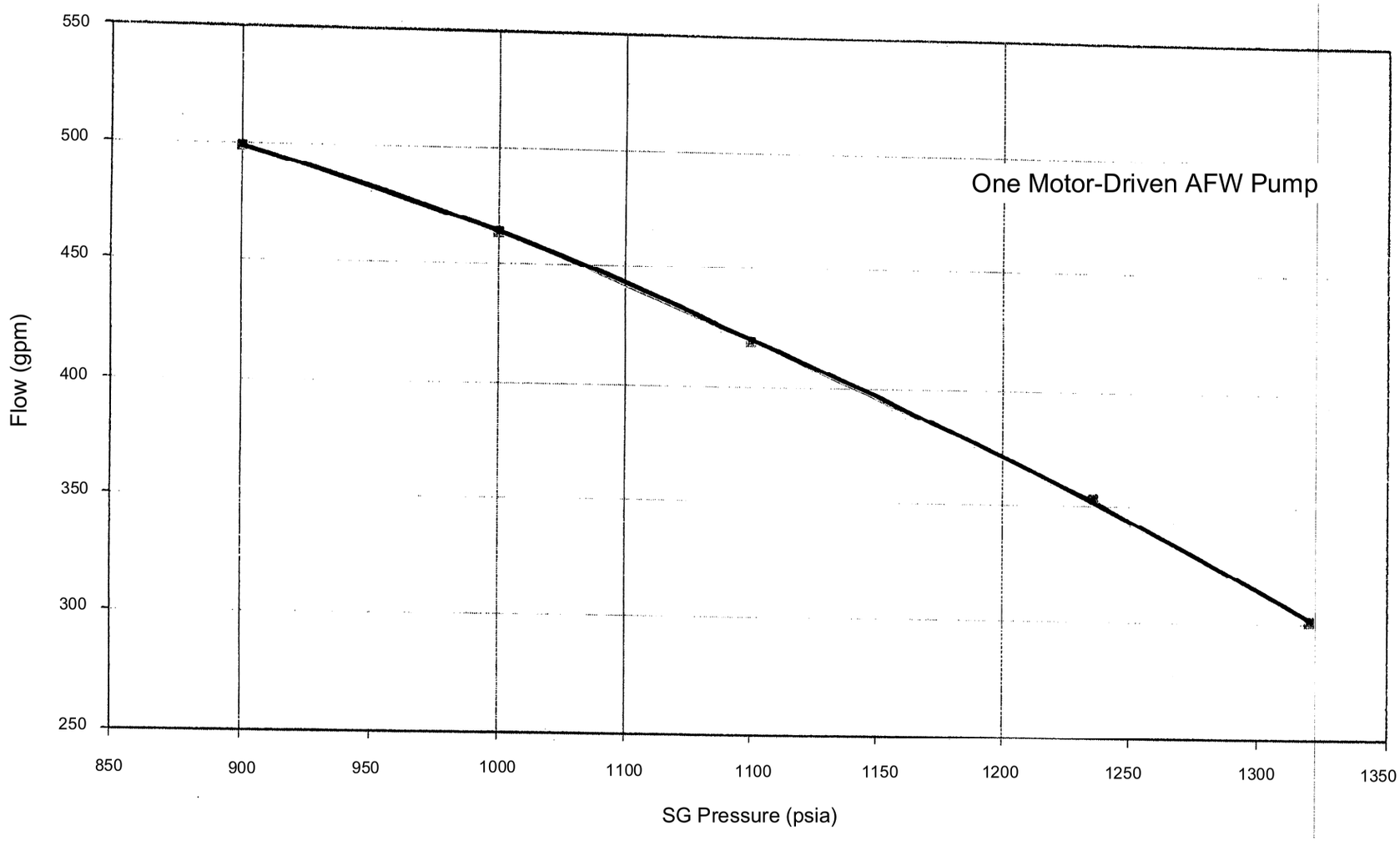


FIGURE 10.4–12 MINIMUM AUXILIARY FEEDWATER FLOW TO TWO STEAM GENERATORS BETTER ESTIMATE LOSS OF NORMAL FEEDWATER EVENT FOR RELIABILITY ANALYSIS



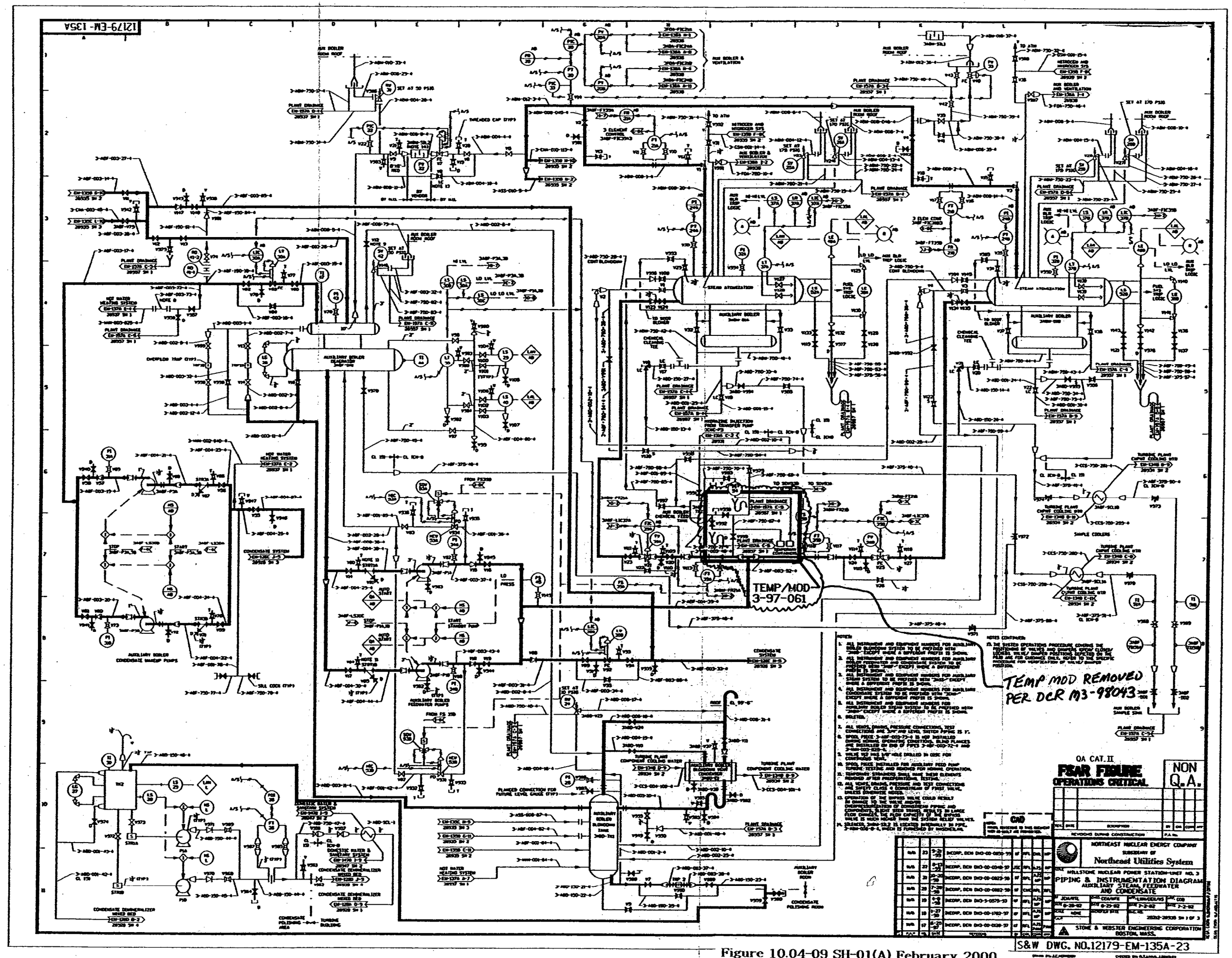


Figure 10.04-09 SH-01(A) February 2000