CHAPTER 10: STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system for Fermi 2 includes a tandem-compound, single-stage reheat, six-flow exhaust, 1800-rpm turbine with nominal 43-in. (8th stage) last-stage buckets (blades). The turbine nominal rating at the generator terminals is 1235 MWe at 1.5 in. Hg abs, 100 percent reactor flow, and zero percent makeup. The design rating of the generator coupled to the turbine is 1,350,000 kVA at 22,000 V, 60-Hz frequency, and 0.90 power factor. Steam at 981.0 psia, 544°F, and 0.46 percent moisture is provided by the nuclear steam supply system (NSSS) at the turbine throttle to drive the main turbine generator.

Moisture separation with one stage of reheat is provided between the high-pressure and the low-pressure turbines for all steam entering the low-pressure turbines. Steam from the low-pressure turbines is condensed in a single-pressure condenser of divided water-box design. Condensate is collected in the condenser hot-wells and pumped through the condensate/feedwater cycle to the NSSS. Heater drains are cascaded into the condenser, except for the heater drains from heaters 5 and 6. The condensate/feedwater from these is pumped forward into the reactor feed pump (RFP) suction.

The condensate and feedwater system supplies feedwater to the NSSS through a condensate cleanup system and then through six stages of extraction feedwater heating.

Circulating water from a circulating water reservoir is pumped through the main condenser and returned to the cooling towers. There, the heat rejected from the steam conversion system is dissipated into the atmosphere. Makeup water for the circulating water system is taken from Lake Erie.

The heat balance at design rating is shown in Figure 10.1-1. Key cycle characteristics are shown in Table 10.1-1.

Normally, the turbine and auxiliary equipment use all the steam being generated by the NSSS; however, an automatic pressure-controlled 23.5 percent-capacity turbine bypass system discharges excess steam directly into the condenser. The capacity of this system is 23.5 percent of the rated reactor flow.

The steam and power conversion system is designed to use the energy available from the NSSS. It has the capability of accepting at least rated reactor flow and reactor pressure for safe, continuous operation. The necessary biological shielding for the main turbines, RFP turbines, moisture separators and reheaters, and condenser is provided for personnel protection.

The individual components of the steam and power conversion system are based on a proven conventional design acceptable for use in large central-station power plants. All auxiliary equipment has been sized on the basis of the design flow rating and pressure rating with turbine valves providing adequate margin for pressure control in accordance with the heat balance shown in Figure 10.1-1. Design margins have been included to ensure adequate capacity under all operating circumstances.

The steam turbine is provided with an electro-hydraulic control (EHC) system having three electrical speed inputs. Speed logic is redundantly processed in both electronic and hydraulic channels. Turbine steam supply valves are provided in serial pairs; a stop valve is actuated by either of two redundant overspeed trip systems followed by a controlling valve modulated by the speed governing system. The latter valve is tripped by either of the two overspeed trip systems. Failure of a single component in the speed control system does not lead to excessive overspeed.

Logic circuits are provided for turbine protection and operation. Additionally, testing circuits for the turbine steam valves are provided. Emergency trip devices include a manual trip, a mechanical overspeed trip, an electrical overspeed trip, and an electrical vacuum trip.

None of the components of the power conversion systems are required to operate to ensure a safe reactor shutdown. This is because reactor safety systems are provided that are designed to protect the reactor under all conditions, including complete isolation from the power conversion systems. Therefore, reliability of these power conversion systems, except where concerned with control of radioactivity, is primarily a function of system operating requirements.

Redundant equipment is provided, wherever feasible, to prevent excessive loss of plant output or excessive frequency of reactor scram.

The safety-related aspects of several postulated failures that might occur within the power conversion system have been considered. The following specific situations have been analyzed:

a. Breaks in the feedwater system that allow discharge of contaminated feedwater into the turbine building

b. Failure of the air-ejection line resulting in discharge of activity directly into the turbine building

c. Missiles generated by a postulated turbine failure

d. Introduction of contaminants into the reactor vessel via the condensate/feedwater system.

Feedwater system breaks and failure of the air-ejection line are both discussed in Chapter 15. These analyses indicate that the amount of radiation released into the environment following any one of these studied incidents is within acceptable limits.

The effects of turbine missiles are analyzed in Subsections 10.2.3 and 3.5.1.2.2. The conclusion is that postulated turbine missiles are not a plausible event.

Regulatory Guide 1.56, Maintenance of Water Purity in Boiling Water Reactors, will be met to ensure that contaminants from the feedwater entering the reactor vessel are kept at acceptably low levels.

TABLE 10.1-1 SUMMARY OF IMPORTANT NOMINAL AND PERFORMANCE CHARACTERISTICS OF THE POWER CONVERSION SYSTEM

Turbine Data	
Manufacturer	General Electric Company Turbine Generator, LTD.[a] GE for HP and LP Steam Path replacement components
Type / LSB length, in.	43 (8th stage)
Number of cylinders	One higher pressure, three low pressure
Gross electrical output at the generator terminals (MWe)	1235
Condenser pressure, in. Hg abs	1.5
Final feedwater temperature, °F	426.5 (nominal)
Steam conditions at throttle valves inlet	
Flow, lb/hr	13,722.820
Pressure, psia	981.0
Temperature, °F	544
Enthalpy, Btu/lbm	1190.6
Moisture content, percent	0.46
Turbine cycle arrangement	
Number of steam reheat stages	One
Number of feedwater heating stages	Six
Heater drain system	Heaters 5 and 6 pumped forward
Feedwater heaters in condenser neck	Numbers 1 and 2
Type of condensate demineralizer	Mixed-powdered-resin type
Main steam bypass capacity, percent of rated reactor flow	23.5

[a] Formerly English Electric Co,

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Refer to Plant Drawing C1C OUT

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FIGURE 10.1-1

HEAT BALANCE AT 100 PERCENT
REACTOR FLOW

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The turbine generator is designed to meet the following conditions:

a. Gross electrical output at the generator terminals at 100 percent reactor flow is 1235 Mwe.

b. Steam conditions at the turbine throttle valves inlet

1.	Flow, lb/hr	13,722,820
2.	Pressure, psia	981.0
3.	Temperature, °F	544
4.	Enthalpy, Btu/lbm	1190.6
5.	Moisture content, percent	0.46

c. Exhaust pressure, in. Hg abs 1.5

d. Final feedwater temperature, °F 426.5

e. Stages of feedwater heating Six

f. Stages of steam reheating One

These figures represent the 100 percent reactor flow heat balance conditions shown in Figure 10.1-1.

The unit is to be operated initially in a base-loaded manner but has the provision to be operated in a load-following manner when this becomes beneficial from the standpoint of system reliability and economics.

The nuclear steam supply system (NSSS) and turbine have the ability to provide continuous load-following capability over a range of approximately 31.5 percent of rated power. This power change via recirculation flow can be accomplished at the rate of 1.5 percent/sec for both load increases and decreases. Step-change electrical load reductions that do not exceed 23.5 percent of rated power are handled by operation of the main steam bypass system without requiring an associated change in reactor power.

10.2.2 Description

10.2.2.1 Turbine Generator

The General Electric Company Turbine Generator, Ltd. (formerly English Electric Co.) turbine is a four-casing, tandem-compound, six-flow, 1800-rpm unit that has been modified. During RF05, the LP Turbine Steam Path consisting of rotors, buckets (blades), diaphragms and steam flow guides was replaced with GE designed components. The HP Turbine Steam Path was replaced during RF07 with GE designed components. The major components replaced were the rotor, diaphragms, associated seals, and coupling spacers. An inlet snout was added to provide the steam flow path into the first stage nozzles. An ac generator is connected to the turbine shaft. The excitation system consists of an automatic voltage regulator and excitation transformer.

The turbine consists of one double-flow high-pressure element in tandem with three double-flow low-pressure elements.

Turbine-generator bearings are lubricated by a conventional pressurized oil system. Two 100 percent electric (ac) motor-driven pumps supply bearing oil to the turbine generator under normal operation. Normally one ac pump is running and one is a spare. One electric (dc) motor-driven backup pump is provided in the event both ac pumps fail as a result of a loss of ac power.

Steam from the NSSS enters the high-pressure turbine through four 24-in. stop valves and governing control valves. One stop valve and one control valve form a single assembly. After expanding through the high-pressure turbine, the steam flows through the moisture separators and reheaters to the six intermediate stop valves and six intercept valves into steam lines leading to the three low-pressure turbines. Steam from each low-pressure turbine is then exhausted into the main condenser.

Moisture separation and reheating of the steam are provided between the high-pressure and low-pressure elements in two parallel shells, each of which contains combined moisture-separator-reheater assemblies. A separator-reheater assembly is located on each side of the turbine parallel to the turbine shaft.

The turbine generator is protected from excessive overspeed by two emergency overspeed trip protection systems, the mechanical overspeed trip system and the electrical overspeed trip system. The mechanical overspeed trip system consists of two redundant systems using two separate spring-loaded throwout plungers mounted on the turbine shaft. Should the turbine accelerate to its over-speed trip set point, each plunger strikes its respective position limit switch mounted adjacent to each of the plungers, energizing a system of protective relays that will trip the turbine.

The electrical overspeed system uses four separate and redundant channels of speed measurement. The four channels are fed through a network of comparative logic gates. This comparative logic system monitors the speed input signals and alerts the operator with an alarm if any one of the four inputs fails to match the others. The system ac power supply is redundant with automatic throwover to the backup ac supply. The power supplies, main, backup, and test, are monitored for loss of potential and alarmed for operator corrective action. Figure 10.2-1 is the block diagram of the electrical overspeed system.

The generator is sized to accept the gross rated output of the turbine at rated reactor pressure and reactor flow at the throttle. The generator is a direct-coupled, 60-Hz, three-phase, 22,000-V unit designed at 1,350,000 kVA at 0.90 power factor, and has a maximum hydrogen pressure of 75 psig. The generator shaft seals are oil-sealed to prevent hydrogen leakage. The static excitation system has been sized for a rated field current of 5,189 A at a rated field nominal voltage of 575 VDC.

Excitation power for the generator rotor is supplied from the excitation transformer through thyristor bridges in a configuration to allow continuous operation with a minimum of two bridges in service at full power, with the excitation being controlled by the excitation control cubicle.

10.2.2.2 Cycle Description

Steam is fed from the reactor, through four lines and associated isolation valves, into a 52-in. common manifold. From the manifold, steam is supplied to the high-pressure turbine through four 24-in. lines. Each line contains a turbine stop valve and a turbine control valve. The control valves adjust the quantity of steam admitted to the turbine and thus control the reactor steam pressure and the electrical power output.

If operation with one control valve out of service is necessary, steam is supplied to the high-pressure turbine through three 24-in. lines. An evaluation of the limiting transients and issues associated with one turbine stop or control valve out of service for Fermi 2 has been documented in Reference 2. The evaluation is qualitative and independent of fuel type through GE14. The conclusions are generic and can be applied to both current and future cycles of Fermi 2. Reference 3 confirms that the Reference 2 evaluation is applicable to GNF3 fuel with the power and steam flow capacity updates for 1 Turbine Control Valve Out of Service (TCVOOS) at 3486 MW. The assessment with one turbine stop or control valve out-of-service in Reference 2 along with Reference 3 covers the adequacy of the current power and flow dependent MCPR and MAPLHGR limits and the impact on ECCS/LOCA and ATWS. The assumptions for the assessments and conclusions are that operation with one steam feed to the main turbine isolated by a TCV or TSV is acceptable if:

a. Core thermal power will be at or below 91.5 percent
b. Operating dome pressure is maintained at or above normal off-rated operating dome pressure but below the LCO maximum dome pressure
c. The turbine bypass system is operable
d. The moisture separator reheaters are operable
e. Operating with normal feedwater heating
f. Reactor Flow Limiter Setpoint is at 115 percent or higher.
g. Maximum Steam Flow Available is 109.4% rated steam flow.

During an electrical load reduction, steam may be bypassed directly to the condenser to maintain constant reactor pressure. The capacity of the bypass system is 23.5 percent of rated reactor flow.

After passing through the high-pressure turbine, steam is exhausted to the moisture separators and reheaters, where it is reheated by steam taken from the main steam lines ahead of the turbine stop valves. The reheated steam then passes into the low-pressure turbines. There, the steam is equally divided among the three low-pressure turbines and is eventually exhausted into the condenser. The condensed heating steam is drained to the No. 6 feedwater heaters.

Steam is extracted from six points on the turbine for feedwater heating. There is one extraction point from the high-pressure turbine, one from the high-pressure turbine exhaust, and four from the low-pressure turbines, as shown in Figure 10.2-2.

Steam is supplied to the reactor feed pump (RFP) turbines from two sources: (1) the main steam manifold during startup and low-load operation and (2) the hot reheat line during normal operation.

10.2.2.3 Instrumentation Application

The turbine generator uses an electro-hydraulic control (EHC) system that controls the speed, load, pressure, and flow for startup and planned operation, and trips the unit when required. The EHC system operates the high-pressure stop valves, bypass valves, control valves, low-pressure stop and intercept valves, and other protective devices. Turbine-generator supervisory instrumentation is provided for operational analysis as well as for pre- and postmalfunction diagnosis.

The automatic control functions of the turbine generator are correlated with the reactor pressure control and recirculation control. For details, see Subsection 7.7.1.

The turbine EHC system uses solid-state electronics and high-pressure hydraulics to control the nuclear steam flow from the reactor.

Four major functions are performed by the turbine EHC system, as follows:

a. Speed control

b. Pressure control

c. Valve position control

d. Supervisory control.

Speed control is accomplished by comparing a turbine shaft speed signal to a speed reference to produce a speed error signal. In addition, a digital technique is used to produce a turbine acceleration signal from the turbine shaft speed pickup pulses. This acceleration signal is compared to a reference to produce an acceleration error signal that is summed with the speed error signal to produce a speed/acceleration error. The speed/ acceleration error is modified by an adjustable proportional constant to produce a valve position demand. The speed governing system has been designed using three redundant systems.

Pressure control is accomplished by comparing turbine inlet steam pressure to a pressure reference and thereby producing a pressure error signal. This pressure error is modified by an adjustable electronic regulator to obtain a valve position demand.

Unitized actuators at each turbine steam valve accept the electrical signals from the pressure control, speed control, or the supervisory control and position the valve in the required manner. Each valve is provided with an individual valve actuator, which eliminates the need for extensive high-pressure control oil piping. The unitized actuator is a self-contained, electro-hydraulic valve positioner that converts the electrical control signals to valve position. Each unitized actuator is designed to perform a specific valving function.

Supervisory control is provided to maintain the turbine in a safe controlled state or to initiate a rapid shutdown in case of an emergency.

Rapid shutdown is achieved by initiating the fast closure mode of valve control. Under this mode of control, the maximum closure rate is obtained. Fast-closure full-stroke travel time of the turbine stop valves is 0.20 to 0.22 sec. The fast-closure full-stroke travel time of the turbine control valves is 0.20 to 0.22 sec. Low-pressure stop and intercept valves close in approximately 1.0 sec when operating in the fast closure mode.

10.2.2.4 Emergency Control Operations

Loss of electrical load with respect to subsequent interactions should be considered under three conditions (a., b., and c. below). For these three conditions, the turbine-generator emergency overspeed will not exceed 120 percent of rated speed (1800 rpm).

a. Generator breakers (two) trip

   The generator has a system of protective devices that protect the generator from damage. This protection is achieved by tripping open the generator breakers. The generator breakers have position switches that will initiate a direct turbine trip when both breakers are tripped open.

b. System disturbances resulting in sustained loss of electrical load

   If the turbine generator has been running at maximum load and the load on the generator is suddenly lost (not the result of generator breaker trips), the following events will occur in controlled rapid succession:

   1. The turbine will accelerate at a rate proportional to loss in electrical load until the turbine control system starts to close the control valves
   2. The turbine control will initiate the fast closure mode of the turbine control valves (TCV) when the turbine acceleration exceeds a prescribed trip setpoint
   3. The operation of the HP stop valve and the associated RPS turbine stop valve closure limit switch initiates fast closure mode which will initiate a direct reactor scram
   4. The control valves will close at the maximum closure rate by means of the fast-acting solenoid valves
   5. The entrained steam between the valves and the turbine, in the turbine steam casing, and in the extraction lines will expand. Some of the accumulated water will flash into steam, supplying energy to the turbine at a relatively moderate rate
   6. The turbine speed will cease to increase when the entrained steam has stopped expanding. The turbine will trip on reverse power when its speed is less than synchronous
   7. Generator breaker and turbine trips will be initiated on reverse power to the generator if the loss of electrical load has not already isolated the generator from the system
   8. The turbine will coast down until turning gear speed is established. The turning gear will maintain slow rotation of the turbine to allow even cooling during the desoaking period.

c. Partial loss of electrical load

   On a small loss of load, the turbine will accelerate slowly. Assuming that the fast closure mode is not initiated, the bypass valves will divert the nuclear steam supply to the condenser until the steam supply can be decreased.

The emergency trip system closes all valves (turbine stop valves, control valves, intercept valves, and reheat stop valves), shutting down the turbine on the following signals:

NOTE: Setpoints are approximate and are for illustration only.

a. Turbine speed approximately 7 to 10 percent above rated speed by
   1. Magnetic speed pickups - four provided (106 to 108 percent speed)
   2. Overspeed trip plungers - two provided (107 to 110 percent speed).
b. Vacuum less than a preselected value (7.5 in. Hg abs)
c. Excessive thrust-bearing wear (±0.050 in.)
d. Low flow of generator stator water coolant (600 gpm or less after a time delay of 60 seconds)
e. High stator-coolant outlet temperature (195°F)
f. Generator protection, including reverse-power sustained and both generator breakers tripped
g. Low lube-oil pressure - below 10 psig after a 20-sec time delay
h. Loss of two speed-sensing signals (failure of two of three computing channels)
i. Loss of both main and emergency power supplies to the EHC cubicle
j. High pressure in separator-reheaters - 256 psia
k. High reactor water level
l. Manual trip from control room panel
m. Deleted
n. High shaft or pedestal vibration after a 7.5 second (maximum) time delay with
   1. “Hi Hi” (12 mils shaft or 10 mils pedestal) on any bearing and
   2. “Hi” (<10 mils) on an adjacent bearing
o. Hydrogen-seal oil-pressure differential low - 10 psig after a 20-sec time delay
p. Hydrogen gas temperature high - 185°F
q. Both main lube-oil reservoir emergency valves open.

10.2.2.5 Turbine-Generator Supervisory Instruments

The turbine supervisory instrumentation is located in the main control room and is sufficient to detect malfunctions.

The turbine-generator supervisory instrumentation includes monitors for the following:

a. Electrical load
b. Shaft speed
c. Control valve position
d. Vibration and eccentricity
e. Thrust-bearing wear
f. Exhaust hood temperature and spray pressure
g. Oil system pressures, levels, and temperatures
h. Bearing metal and oil drain temperatures
i. Shell temperatures
j. Valve positions
k. Shell and rotor differential expansion
l. Hydrogen temperature, pressure, and purity
m. Stator-coolant temperature and conductivity
n. Stator winding temperature
o. Excitation equipment area temperature
p. Steam seal pressure
q. Gland steam condenser vacuum
r. Steam chest pressure
s. Hydrogen-seal oil pressure.

10.2.2.6 Testing Provisions

Provisions are made for testing each of the following devices while the turbine generator is operating:

a. Main stop and control valves
b. Intermediate stop and intercept valves
c. Overspeed governor
d. Turbine extraction nonreturn valves (excluding small valves)
e. Vacuum trip
f. Lubricating oil system backup pumps.

The following testing and inspection activities are performed in accordance with the manufacturer's recommendations and operational experience or constraints:

a. The mechanical and electrical overspeed trip systems are operated and checked

b. The main steam stop valves, main steam control valves, low pressure stop valves, and intercept valves are dismantled and inspected

c. The main steam stop valves, main steam control valves, low pressure stop valves, and intercept valves are exercised.

10.2.3 Turbine Missiles

Fermi 2 was designed with barriers to resist potential turbine missiles. These barriers were designed to protect the safety related plant components from a design basis turbine missile which, prior to the replacement of the LP turbines during RF05, was a 120° segment of the largest main low-pressure turbine wheel. That missile weighed 8650 lbs. and had an initial velocity of 383 mph.

During the fifth refueling outage, the three built-up low pressure rotors, including blades and diaphragms, for Fermi 2 LP turbines were replaced. The maximum attainable speed of the new rotors will be approximately 218-222% of rated speed. At this point, the steam flow through the rotating steam path is well away from design conditions with some stages being driven by the steam while the remainder absorb energy. This scenario assumes that all the buckets remain intact on the rotor, the generator does not loosen retaining rings, wedges or field bars, and that the unit does not experience severe rubbing, all of which would keep the rotor at lower speeds.

Considering the minimum rotor material specification strength values, and assuming all buckets remain attached, the minimum overspeed capability of the rotors is about 219-225%. Using typical strength values, the overspeed capability of the rotors is considerably higher than the shrunk-on designs and exceeds the maximum overspeed the rotors can attain. However, the turbine overspeed control system is designed to limit maximum turbine overspeed of 120% of the turbine rated speed.

A complete failure of the control system and safety-related items is required to reach the event described. The probability of this occurring is well below 10 to the -8 power. In conclusion, the rotor stress levels are quite low; the probability of missiles being generated by the low pressure rotors is not present.

During the seventh refueling outage, the high pressure rotor, including blades and diaphragms for Fermi 2 HP turbine, was replaced. Although the HP rotor was replaced after the LP rotors, the LP rotor document regarding nuclear turbine missile analysis still governs. This concluded that blades will not penetrate outer casings. The minimum speed at which the HP blades fail is bounded by the LP turbine analysis performed for RF05.

Subsequent to replacing the low pressure turbine rotor, the generator rotor was replaced with a rotor that is equivalent in design, mass, and configuration. The exiting turbine missile calculations are not impacted by this second replacement and indicate that missiles emanating from the generator rotor will be stopped before they can completely breach their respective outer casings. Concluding, with the low-pressure rotor replacement, there will no longer be a design basis turbine missile at Fermi 2, however the originally designed missile barriers remain intact.

The probability of a failure of a rotor or bucket (blade) is further minimized by the selection of materials, manufacturing process, preservice inspections and established inservice inspection programs.

The LP rotors are a GE proven monoblock design, whereby a rotor is machined from a single forging that accounts for bucket (blade) attachment points, as well as the coupling configuration; thus, eliminating the need for shrunk on discs and couplings. The new rotors are forged out of a GE proprietary NiCrMoV material that is similar to ASTM A470 Class 6 which meets the requirements specified in the purchase specification. The monoblock forging material chemistry is optimally balanced to have high hardenability, to achieve good fracture toughness at the required tensile strength, low tramp elements to minimize temper embrittlement and low sulfur to minimize harmful segregation. The rotors have the bucket (blade) wheel dovetails machined directly into the rotor forgings. The first six stages utilize tangential entry “pinetree” dovetails to attach the buckets, the last two stages utilize radial entry finger dovetails with pins.

The buckets (rotor blades) are either fabricated from bar stock or forged. The material is a GE proprietary material that consists of nominal 12% Cr. and is similar to ASTM A479, except with more stringent quality requirements. To protect against moisture erosion of the blade tips, GE uses flame hardening in lieu of stellite shields to provide an equivalent resistance to erosion, and to minimize the addition of cobalt into the primary system. The last four bucket stages (5, 6, 7 and 8) will be flame hardened. In addition to flame hardening, stages 5, 6 and 7 have moisture removal grooves that help direct water to drainage paths through the diaphragms. This design helps prevent water build-up, and that will reduce bucket’s loading during turbine operation.

The first six bucket stages have standard GE shot peened pinetree dovetails for attachment to the rotor wheels. The last two stages have finger dovetails with shot peened pins for attachment to the rotor wheels. Shot peening reduces concentrated stresses, therefore significantly improving the material resistance to stress corrosion cracking and improving the dovetail reliability.

The last stage bucket is what GE refers to as a 43C design. The bucket length is only 43 inches as compared to the original last stage blade which was approximately 45 inches. The 43C bucket is based on GE proven designs and latest technology utilizing, at its outer periphery, a two-piece over-under continuous cover connecting each bucket (blade) in its row together. This helps maintain the space at the bucket tips where the steam flows through and helps resist blade twisting, thus allowing for a more efficient bucket design.

The turbine supervisory instrumentation is used as a continuous inservice monitoring process of the turbine and associated equipment performance.

Edison performed the inspection of the low-pressure turbine disks during the second refueling outage in accordance with the Technical Specifications. This inspection consisted of volumetric examination of the disk bore area using ultrasonic techniques. Future inspection requirements will be per the turbine manufacturer’s recommendation.

10.2.4 Evaluation

The primary source of activity in the steam and power conversion system is radiation from ^{16}N, formed by activation in the reactor. Nitrogen-16 has a half-life of approximately 7 sec. The activated nitrogen is carried with the steam to the turbine. Fission-product noble gases and other activation gases, such as ^{19}O, ^{17}N, and ^{13}N, are also carried with the steam to the turbine. Some nongaseous fission and activation products are present in the turbine as a result of moisture carryover in the steam from the NSSS.

The activity entering the low-pressure turbine is reduced because of the presence of moisture separation and transit time between the high-pressure and low-pressure turbines, which permits the ^{16}N to decay.

Most of the noncondensible gases in the condenser are removed by the steam-jet air ejectors to the offgas system, which is described in Section 11.3. The activity remaining in the condensate is reduced significantly by the nominal 4-minute holdup time in the condenser hotwell.

Shielding requirements are discussed in Section 12.1. The turbine generator is in an administratively controlled access area.

10.2 TURBINE GENERATOR

REFERENCES

1. USAEC/ACRS subcommittee meeting minutes, March 2, 1971, Enrico Fermi Atomic Power Plant - Unit 2, AEC Docket No. 50-341

2. GNF DRF: GE-NE-J11-03920-07-01, “Turbine Control Valve Out-of-Service for Enrico Fermi Unit-2,” Revision 0, October 2001.

3. TRVEND 24MCGNF3FTRT1104, “GNF3 Fuel Design Cycle-Independent Analyses for Fermi 2 Power Plant,” Revision 1, December 2023. (GEH File: 004N7423), (Edison File# T19-158).

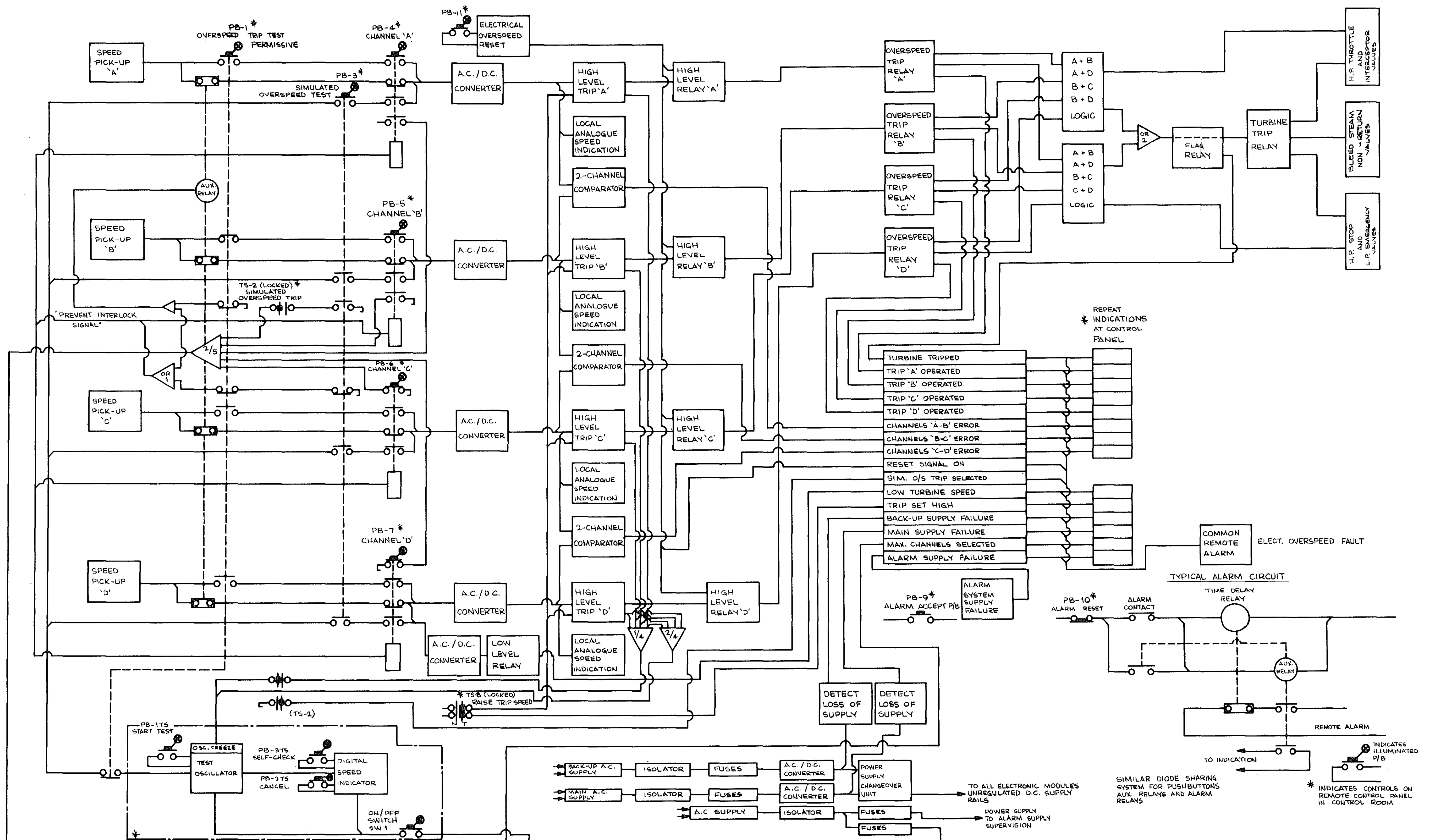

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FIGURE 10.2-1

TURBINE GENERATOR ELECTRICAL OVERSPEED PROTECTION SYSTEM BLOCK DIAGRAM

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FIGURE 10.2-2

EXTRACTION STEAM SYSTEM

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 Design Bases

10.3.1.1 Safety Design Bases

To satisfy the safety design bases, the main steam lines from the reactor up to the second isolation valves are designed according to the following piping classification, which is in accordance with the ASME Boiler and Pressure Vessel Code:

a. From the reactor to the drywell wall - ANSI B31.7, Class A, Category I

b. From the drywell wall to the outer main steam isolation valve - Section III, Class 1, Category I

c. The outer isolation valve to the third isolation valve is seismically qualified and designed to ANSI B31.1.0, Group D, Category II/I.

10.3.1.2 Power Generation Design Bases

The main steam supply system is designed to fulfill the following functions:

a. To deliver steam from the nuclear steam supply system (NSSS) up to the turbine generator

b. To provide steam for the reheater and the steam-jet air ejectors

c. To provide steam for the reactor feed pump (RFP) turbines during startup and low-load operations

d. To provide steam for the turbine seal system and flange warming during startup

e. To deliver excess steam produced in the NSSS to the condenser during startup and transients whenever the steam used by the turbine is less than that produced by the NSSS.

10.3.2 Description

The main steam supply system is shown in Figure 10.3-1.

The main steam piping consists of four 24-in. lines from the outboard (second) main steam isolation valves (MSIVs) to the 52-in. manifold (including the motor-operated [third] MSIVs), and then to the locations described in Subsection 10.3.1.2. The turbine stop valves and MSIVs may be tested independently during plant operation.

The main steam line pressure relief system, main steam line flow restrictors, and MSIVs are described in Subsections 5.2.2, 5.5.4, and 5.5.5, respectively.

The design pressure-temperature rating of the main steam piping is 1250 psig/575°F, the same as the design pressure-temperature of the NSSS. The Category I design requirements are placed (1) on the main steam piping from the reactor up to the second isolation valve and (2) on all branch lines up to and including the first valve, which is either normally closed or capable of automatic closure during all modes of normal NSSS operation. The main steam line is also analyzed for the dynamic loadings caused by fast closure of the turbine stop valves. For further information on the design of the main steam piping and valves, see Subsection 6.2.6.6.

A 52-in. manifold is installed ahead of the turbine stop valves. This provides a common point for the four steam lines from the reactor, the four steam lines to the turbine, the two bypass steam lines, the steam line to the RFP turbines, and plant auxiliaries.

A drain line is connected to the low points of each main steam line, both inside the drywell and outside the containment. Both sets of drains are headered and connected by valving to permit steam line isolation and drainage to the main condenser hotwell. To permit draining the lines for maintenance, an additional drain is provided from the low points of the drains to the radwaste system.

The drains inside and outside the containment are capable of equalizing pressure across the MSIVs prior to restart following steam line isolation. Assuming all MSIVs are closed, and the steam lines outside the drywell have been depressurized, the isolation valves outside the drywell are opened first. Then the drain lines are used to warm up and pressurize the outside steam lines. Finally, the MSIVs inside the drywell are opened.

10.3.3 Evaluation

The seismic and quality group requirements of all main steam lines and components are defined in Section 3.2. This design ensures conformance with the intent of Regulatory Guide 1.26.

Per Subsection 6.2.6, a re-analysis of the Loss-of-Coolant Accident (LOCA) using an Alternative Source Term (AST) methodology made it no longer necessary to credit the Main Steam Isolation Valve Leakage Control System (MSIVLCS) for post-LOCA activity leakage mitigation. Conformance with Regulatory Guide 1.96 was superseded by License Amendment 160, which approved the use of the AST methodology and the deletion of the MSIVLCS (Ref. Subsection A.1.96). The main steam lines from the RPV to the third MSIVs are seismically qualified as indicated in License Amendment 160.

10.3.4 Inspection and Testing Requirements

Inspection and testing are carried out in accordance with the requirements of Regulatory Guide 1.68 and ANSI N18.7. The mainsteam line is hydrostatically tested to confirm leaktightness. All welding in the above steam line is 100 percent volumetrically inspected.

Figure Intentionally Removed
Refer to Plant Drawing M-2002

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FIGURE 10.3-1

MAIN STEAM SYSTEM

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

10.4.1.1 Design Bases

10.4.1.1.1 Performance Requirements

The main condenser provides the heat sink for the turbine exhaust steam, turbine bypass steam, and other turbine cycle flows, and receives and collects flows for return to the nuclear steam supply system (NSSS).

The main condenser accommodates or provides for the following at rated (nominal) full load (see Figure 10.1-1):

a.	Total turbine exhaust steam	8.10×10^6 lb/hr
b.	Total condensate outflow	10.88×10^6 lb/hr
c.	Total condenser heat duty	7.81×10^9 Btu/hr
d.	Number of condenser shells	One
e.	Condenser pressure	1.5 in. Hg abs
f.	Exhaust pressure limit	5.0 in. Hg abs
g.	Circulating water	
	1. Flow(Nominal)	836,700 gpm
	2. Number of passes	One
	3. Temperature to limit condenser pressure to 4.5 in. Hg abs	100°F
	4. Condenser temperature rise	18°F

10.4.1.1.2 Turbine Bypass Steam

The main condenser is designed to accept up to 23.5 percent rated reactor steam flow from the turbine bypass system, as described in Subsection 10.4.4 (also see Figure 10.3-1). This condition is accommodated without increasing the condenser backpressure to the turbine trip setpoint or exceeding the allowable turbine exhaust temperature.

10.4.1.1.3 Condensate Deaeration

One purpose of the main condenser is to deaerate the condensate. More specifically, it is designed to reduce the dissolved oxygen level in the condenser hotwell effluent to 7 ppb or less under normal full-load operation. This level is undesirable from a carbon steel corrosion standpoint. However, experience has shown that the normal dissolved oxygen level will be 10 to 50 ppb. If the main condenser deaerates the condensate values consistently less than 10 ppb dissolved oxygen, actions must be promulgated to restore oxygen levels and/or evaluate the consequences consistent with Owners' Group guidelines and site programs. An Oxygen Injection System has been provided to inject oxygen gas into the condensate system to restore oxygen to normal levels. (See UFSAR Figure 10.4-8(1)).

10.4.1.1.4 Air Leakage

The main condenser is designed to minimize air inleakage. Welded construction is used for the condenser shell and for condenser shell connections and penetrations. Equipment and piping connected to the condenser shell are also designed to minimize air inleakage to the main condenser. The design of the evacuation system is described in Subsection 10.4.2.

10.4.1.1.5 Condensate Detention

The condenser hotwell is designed to store a sufficient volume of condensate to provide a nominal of 4 minutes' effective detention of the condensate to allow for radioactive decay.

10.4.1.1.6 Design Codes

Condenser construction is in accordance with the requirements of Heat Exchange Institute (HEI) standards for steam surface condensers.

10.4.1.2 System Description

During plant operation, steam from the last stage of the low-pressure turbine is exhausted directly downward into the condenser shell through exhaust openings in the bottom of each of the three turbine casings and is condensed. The condenser consists of one shell serving three double-flow, low-pressure turbines. The condenser also serves as a heat sink for several other flows: the two reactor feed pump (RFP) turbine exhausts, cascading heater drains, steam line drains, pump vents and recirculation lines, heater vents, and condensate system makeup.

During transient conditions, the condenser is designed to receive bypass steam, feedwater heater drainage, and moisture-separator drainage. The condenser is also designed to receive relief valve discharges from the feedwater heater shells, steam seal regulator, and the various steam supply lines. The moisture-separator relief valves discharge to the turbine room. These valves are backed up by rupture disks.

The condenser is cooled by the circulating water system, which removes the heat rejected to the condenser as described in Subsection 10.4.5.

The condensate is pumped from the condenser hotwell by the condenser pumps, described in Subsection 10.4.7, and is returned to the feedwater and steam cycle.

The main condenser is a single-pressure, single-shell, single-pass, deaerating-type condenser with divided water boxes. The condenser tubes are 1 in. in diameter, 50 ft in length, and are made of titanium.

The condenser shell is solidly supported on the turbine foundation mat. It has expansion joints provided between each turbine exhaust opening and the steam inlet connections of the condenser shells.

The condenser hotwell has horizontal and vertical baffles. They improve deaeration and ensure a nominal detention of 4 minutes for all condensate from the time it enters the hotwell until it is removed by the condenser pumps.

Valves in the circulating water system permit one-half of the condenser to be removed from service. This might be required in case of a condenser tube leak.

The air leakage and noncondensible gases include hydrogen and oxygen gases contained in the turbine exhaust steam as a result of dissociation of water in the NSSS. These gases are collected in the condenser and passed through the air-cooling section of the condenser, where they are removed by the main condenser evacuation system, described in Subsection 10.4.2.

10.4.1.3 Safety Evaluation

During operation, radioactive steam, gases, and condensate are present in the shell of the main condenser. The anticipated inventory of radioactive contaminants during operation is discussed in Sections 11.1 and 11.3. Shielding for the main condenser is provided as discussed in Section 12.1.

Condensate is retained in the main condenser for a nominal of 4 minutes to permit radioactive decay before the condensate enters the condensate system.

Hydrogen buildup during operation is not a problem because of the provisions for continuous evacuation of noncondensibles from the main condenser. During shutdown, significant hydrogen buildup in the main condenser does not occur because the main condenser is then isolated from the NSSS.

The main condenser is not required to cause or support the safe shutdown of the NSSS or to perform in the operation of NSSS safety features.

Exhaust hood overheating protection is provided by the low-pressure exhaust hood spray systems located just downstream from the last-stage blades of the turbine.

The loss of main condenser vacuum causes the turbine to be tripped. This transient and its effect on the reactor are discussed in Chapter 15.

Four rupture diaphragms on each turbine exhaust hood open at a few pounds per square inch, gage, to protect the condenser and turbine exhaust hoods (15 psig design) against overpressure. Failure of a rupture diaphragm results in radionuclides being admitted directly to the turbine building rather than passing to the offgas system. This specific failure is not analyzed but the results of a more significant event, i.e., failure of the air ejector line, are analyzed in Chapter 15.

Any leakage of circulating water into the condensate is detected by continuous monitoring of conductivity. Leakage of condensate out to the circulating water is detected by radioactivity monitoring in the circulating water reservoir decant line.

10.4.1.4 Tests and Inspections

The condenser shell received a field hydrostatic test prior to initial operation. This test consisted of filling the condenser shell with water and, while at the resulting static head, inspecting all tube joints, accessible welds, and surfaces for visible leakage and/or excessive deflection.

Each condenser water box received a field hydrostatic test and a visual inspection of all joints and external surfaces.

10.4.1.5 Instrumentation Application

The condenser shell is provided with local and remote indications of hotwell level and pressure, including alarms in the main control room.

Condensate temperature is measured in the suction lines to the condenser pumps.

Water-box pressure and temperature are measured.

Conductivity instruments detect leakage of circulating water into the condenser steam space.

Air leakage is monitored at the offgas system.

The condensate level in the condenser hotwell is maintained within proper limits by automatic controls. The controls provide for transfer of condensate to and from the condensate storage tank as needed to satisfy the requirements of the thermal cycle.

The condenser hotwell has heating coils in each of the four hotwell sections, however they are not used at Fermi 2.

Turbine exhaust temperature is monitored and controlled with water sprays to protect the turbine blading and exhaust hood from overheating.

A high condenser backpressure alarm is provided at a nominal 4.5 in. Hg abs.

Turbine trip is activated on loss of main condenser vacuum, when condenser backpressure reaches or exceeds a setpoint of a nominal 7.5 in. Hg abs.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The main condenser evacuation system during normal operation removes the noncondensible gases from the condenser, including air inleakage and dissociation products originating in the NSSS, and exhausts them to the offgas system (see Section 11.3).

10.4.2.2 System Description

The main condenser evacuation system consists of four 25 percent-capacity, two-stage steam-jet air ejector units, complete with intercondensers for normal plant operation and mechanical vacuum pumps for use during startup. Typically, only two of the four steam-jet air ejector units are required for normal operation.

The mechanical vacuum pumps are used to remove the air and offgases from the main condenser. The discharge from the vacuum pumps is routed to the reactor building vent stack via the 2-minute holdup pipe. The offgases from the vacuum pump are discharged directly to the environment. This is acceptable because the vacuum pump is in service when little or no radioactive gases are present. However, the gas is monitored for radioactivity and pumps will be shut down if Technical Specifications limits are exceeded. In addition, the mechanical vacuum pumps are tripped automatically on main steam line high radiation.

When suitable steam is available, the steam-jet air ejectors are put into service to remove the gases from the main condenser after 6 in. Hg abs vacuum has been established in the main condenser by the mechanical vacuum pumps. Main steam, reduced in pressure to a nominal value of 200 psig by an automatic steam-pressure-reducing station, is supplied as the driving medium to the two-stage air ejectors. The first stages take suction from the main condenser and exhaust the gas vapor mixture to the intercondensers. The second stages exhaust the suction gas vapor mixture from the intercondensers to the offgas system. The steam-jet inter-condensers are drained back to the main condenser.

10.4.2.3 Safety Evaluation

The treatment of radionuclide releases from the main condenser via the offgas system is discussed in Section 11.3. Prolonged shutdown of the offgas system can cause significant hydrogen buildup in the condenser and require shutdown of the unit within 5 to 10 minutes, if condenser backpressure warrants.

Failure of the air ejector line leading to the release of radionuclides directly to the turbine building is discussed in Chapter 15.

Automatic trip of the mechanical vacuum pumps on main steam line high radiation mitigates the potential release of radionuclides through this pathway during a control rod drop accident as described in Chapter 15.

10.4.2.4 Tests and Inspections

All tests and inspections of the equipment that is part of the main condenser evacuation system are performed in accordance with ANSI N18.7.6 and the applicable section of Regulatory Guide 1.68.

10.4.2.5 Instrumentation Application

Process instrumentation applying to the evacuation system is described in Section 11.4. High radiation at the main steam line radiation monitors will trip and isolate the vacuum pumps. High radiation at the 2-minute holdup pipe or from the offgas system causes an alarm signaling the operator to take corrective action.

10.4.3 Main Turbine Gland Sealing System

10.4.3.1 Design Bases

The main turbine gland sealing system prevents air leakage into, or radioactive steam leakage out of, the main turbine.

The main turbine gland sealing system is designed to seal the main and RFP turbine shaft glands and valve stems (high-pressure stop, control, low-pressure stop, intercept, and bypass valves).

10.4.3.2 System Description

The turbine gland sealing system (Figure 10.4-1) consists of a startup steam supply from the 52-in. manifold or from the auxiliary boiler, steam seal pressure regulators, steam seal header, one full-capacity gland steam condenser, two full-capacity exhauster blowers, and the associated piping, valves, and instrumentation.

Sealing steam for turbine shaft packing glands and valve stem packing glands is supplied from the steam seal header, which is maintained at a positive pressure of approximately 2 psig. During startup and low load, the header is supplied with live steam from the 52-in. manifold or from the auxiliary boiler. At normal load, the turbine becomes self-sealing as the seal header is then supplied with steam from the high-pressure turbine center gland.

The outer pockets of all glands are routed through the gland steam condenser, which is maintained at a slight vacuum of approximately 20 in. H_2O by the exhauster blowers. This positively prevents escape of steam from the glands into the turbine room. Instead, air is drawn into the outer glands at these points, and the steam/air mixture is routed to the gland steam condenser. The gland steam condenser, which is cooled by the main condensate flow, condenses the gland steam and returns this to the main condenser, while allowing saturated air and noncondensible gases to be drawn out by the exhauster.

The gland steam exhauster discharges to the reactor building vent by way of the 2-minute holdup pipe. This flow is throttled by valve VR3-2578 to keep the discharge as low as possible but still maintain proper vacuum. The exhausters are tripped automatically on main steam line high radiation.

10.4.3.3 Safety Evaluation

The turbine gland sealing system provides a continuous supply of steam to the turbine shaft glands and the valve stems.

The high-pressure turbine shaft packing can accommodate a range of turbine shell pressures from zero to full-load pressure. The low-pressure turbine shaft packing seals against vacuum at all times. The sealing steam enters the high- and low-pressure turbine shaft packings and the valve stem packings through the inner annulus pocket. Steam is positively prevented from leaking into the turbine room by maintaining a vacuum at each gland outer pocket at all times. This vacuum is provided by the gland steam exhauster. A standby exhauster is provided.

If exhauster vacuum falls below approximately 10 in. H_2O, caused for example by loss of ac power, a vacuum switch initiates the closing of the live steam supply to the gland steam header.

An analysis of possible failure modes of the turbine gland sealing system is presented in Chapter 15.

Automatic trip of the gland seal exhausters on main steam line high radiation mitigates the potential release of radionuclides through this pathway during a control rod drop accident as described in Chapter 15. This trip is only required at the low power levels analyzed in the control rod drop accident and is therefore bypassed above the low power setpoint associated with the rod worth minimizer (see Subsection 7.7.1.3.3.5) to minimize the potential for spurious exhauster trips that could result in a malfunction of the turbine glad sealing system.

10.4.3.4 Tests and Inspections

Normal manufacturers' tests are performed on all equipment. The following tests are required for the gland steam condenser: leak test for tube-to-tube-sheet joints, hydrostatic test, and eddy current tube tests.

10.4.3.5 Instrumentation Application

The liquid level in the gland steam condenser is maintained by a control valve connected to the main condenser. Local pressure-control valves are provided to maintain the gland steam header pressure constant at approximately 2 psig, by either supplying or dumping steam as required. If pressure rises above 5 psig, excess steam is discharged to the condenser by a relief valve.

Temperature and pressure gages are installed in a local panel. Test flow orifices are provided to monitor operation of the system.

10.4.4 Turbine Bypass System

10.4.4.1 Introduction

The Fermi 2 bypass system is a composite of passive and active components that provides a steam path following a turbine- generator trip.

The Fermi bypass system has two key features: the live steam supply to the turbine reheaters, which has a nominal flow of 8 percent of nuclear boiler rating, and the electro-hydraulic control (EHC) redundant bypass valves, which are each designed to bypass a nominal 11.75 percent (23.5 percent total) rated reactor flow to the condenser.

Immediately following a turbine or generator trip from rated power, the bypass system will have a nominal capacity of 31.5 percent of nuclear boiler rating (reheater steam supply plus bypass valves). Following a typical trip, the live steam supply is eventually isolated and the pressure control system maintains the setpoint pressure by modulating the bypass valves.

10.4.4.2 Summary

The Fermi bypass system is designed in such a manner that the loss of the bypass system would require multiple random failures in the system. However, as identified in Table 10.4-1, loss of the BOP dc feeding the system causes both bypass valves to close. Because this is very unlikely, the turbine trip without bypass transient was analyzed as the turbine trip with a single bypass valve failure prior to initial fuel load. This event was not the limiting transient with respect to minimum critical power ratio (MCPR) limits.

Edison maintained that the design of the Fermi 2 bypass system obviates the need to consider the turbine trip without bypass to be part of the design basis. Currently, Fermi performs the turbine trip event and the load reject event assuming that all bypass valves fail to open during the transient. The analysis was based on input parameters specified in Table 15.0-1 and used the TRACG computer code. The results are summarized in Subsection 15.2.3. The technical specification for MCPR is frequently based on these results.

The analysis of reheater steam flow, which is important in the turbine trip analysis, is described further in Subsection 10.4.4.3.

10.4.4.3 Passive Bypass (Live Steam to Reheaters)

10.4.4.3.1 Design Bases

The primary purpose of piping the live steam to the reheater is to improve cycle efficiency by drying and superheating the high-pressure turbine exhaust before it enters the low-pressure turbines. In addition, piping live steam to the reheater minimizes the mechanical damage to turbine blades due to erosion by water droplets and the tearing of sealing surfaces due to leakage of wet steam. The reheat steam quality and flow at rated load are illustrated in the heat balance shown in Figure 10.1-1. As a secondary result of live-steam-reheat flow, a passive bypass system exists and continues to operate following a turbine stop and/or throttle valve closure. The length of time this passive system operates is a function of the time required to close the motor-operated isolation valve in the supply line. The rate of decay of flow following the turbine trip is controlled primarily by the thermodynamic response of the reheater's heat-exchange process until the isolation valve closes.

10.4.4.3.2 System Description

Each moisture separator reheater (MSR) is a cylindrical vessel located on either side of the main turbine generator on the turbine floor. The pressure vessel (shell) is approximately 12 ft in diameter and 111 ft long. Each MSR is equipped with a heating bundle at each end of the MSR vessel. The heating bundle consists of 1195 U-tubes configured in two sets of vertically arranged U-tubes, one located on top of the other to provide a "four pass" heating geometry. Each U-tube is 3/4 in. in outer diameter (nominal) with finned surface to promote more efficient heat transfer. Heating/live steam from the reactor enters the bottom bundle of the U-tubes, completes the first two passes, exits to the top bundle and completes the third and fourth passes. The drains from second pass are routed to the Reheater Seal Tank. Whereas the drains from the fourth pass are routed to the shell of the MSR. Cold reheat steam from the high-pressure turbine exhaust enters the bottom of the separator reheater through four inlet connections. The steam is directed upward through the moisture separators, and passes the reheater tube bundles. The reheated steam then leaves the reheater and passes through the low-pressure turbine-stop and intercept valves and into the low-pressure turbines.

Live steam is supplied as shown in Figure 10.3-1. The steam source is the 52-in.-diameter pressure-equalizing manifold which supplies steam to the four turbine inlet connections through the high-pressure turbine-stop valves. The EHC-controlled bypass valves are also connected to this manifold. The live steam passes through two parallel motor-operated isolation valves (N3018F607) and bypass valve (N3018F609) and then through the parallel combination of two pressure-control valves (N30F006 and N30F007) and a full-flow valve (N3018F608). During normal operation at rated load, the isolation valve and the full-flow valve are fully open. On a turbine or generator trip, valve N3018F607 is closed automatically at a nominal 12-inch-per-minute rate. The bypass valve (N3018F609) is used for warmup purposes only. The two automatic pressure control valves are used during initial startup to maintain a controlled heatup rate. These valves are held completely open during normal operation to prevent the lines from forming/collecting condensate. The live steam then flows through the tube bundles inside each reheater where the heat is transferred to reheat the cold steam from the high-pressure turbine.

In addition to reheating the high pressure turbine exhaust steam, the MSRs provide the passive bypass capability to the reactor steam supply system following a main turbine/generator trip. UFSAR section 10.4.4.3.4 discusses the evaluation of the MSR passive bypass flow adequacy during a postulated turbine trip.

10.4.4.3.3 Single-Failure Analysis

Because the amount of live steam flow following a turbine or generator trip, for the time period of interest, does not depend on the action or inaction of an active component, none of the single failures identified can terminate this flow.

10.4.4.3.4 Transient Analysis

During Fermi 2 initial licensing process, the assumed passive bypass flow capability through the Moisture Separator Reheaters (MSRs), following a turbine trip was documented in Detroit Edison Letter to the NRC dated April 27, 1982 (Reference 1). The NRC acceptance of Fermi 2 analysis was based on reviewing the results generated using the NRC approved version of the RETRAN computer code. The NRC Safety Evaluation Report, NUREG-0798, (Reference 2), Supplement 1, September 1981 Section 15. 1, p. 15-1 and NUREG-0798, Supplement 3, January, 1983, Section 15.1, p 15-1(Reference 2) documented the NRC review and acceptance of Fermi 2 methodology. The model included the following physical entities:

a. Main steam and reheat steam lines, isolation valves, and MSR drains

b. High pressure turbine-stop and throttle valves

c. High-pressure turbine

d. Extraction flows to heaters 5 and 6

e. Shell side of reheater

f. Reheater heat transfer

g. Low pressure turbine intercept valves

h. Low-pressure turbines

i. Reheater seal tanks

j. Heaters 5 and 6.

Significant physical entities that affect the passive bypass flow during a turbine trip transient are as follows:

a. The configuration of the reheat steam supply piping

b. The physical characteristics of the MSRs

c. The configuration of the reheater drain piping upstream of the reheater seal tanks

The analysis showed that the passive bypass flow through the MSRs was in excess of the assumed 8% of the nuclear boiler rating (NBR) flow during the first two seconds following a turbine trip.

The original MSRs were replaced during the 2006 Refueling Outage (RF11). The above transient analysis to demonstrate the passive bypass capability was repeated for the replacement MSRs using the NRC approved version of the RETRAN computer code, as documented in "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", Dated October 18, 2005 (Reference 3). The new transient analysis models the steam cycle including the physical entities a through j listed above in order to establish initial steady state conditions. For conservatism, the above RETRAN02 Analysis (Reference 3) did not include the third and fourth passes of either of the two new MSRs. This RETRAN02 analysis (Reference 3) showed that the passive bypass flow through the replacement MSRs remains in excess of the assumed 8% of the nuclear boiler rating (NBR) flow during the first two seconds following a turbine trip.

Additional sensitivity analyses were performed to determine the parameters that may affect the assumed passive bypass flow through the MSRs following a hypothetical turbine trip event, as documented in "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", Dated October 18, 2005 (Reference 3). These sensitivity analyses show that the required passive bypass flow capability through the MSRs can be maintained when: (1)180 tubes are plugged in each of the MSR's first and second passes even after excluding the third and fourth passes in each MSR; and (2) when the volumes of the nearest and the next to the nearest nodes upstream and down stream of the MSRs are varied by plus or minus 10 percent. Therefore, future tube plugging and changes in nodal volumes that are within the bounds of the above sensitivity analysis (Reference 3) can be performed without further analysis.

A bounding (conservative) flow characteristic, documented in "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", (Reference 3) is used as an input to Subsection 15.1.2, Feedwater Controller Failure transient analysis, Subsection 15.2.2 Generator Load Rejection transient analysis and Subsection 15.2.3 Turbine Generator Trip transient analysis, as shown in Figure 15.0-2.

The RETRAN02 Analysis was repeated for operation at 3486 MWt. The revised RETRAN02 Analysis (Reference 8) showed that the passive bypass flow through the MSRs remains in excess of the assumed 8% of the NBR flow during the first two seconds of a trip.

10.4.4.4 Active Bypass (EHC-Controlled Bypass System)

10.4.4.4.1 Design Bases

The EHC-controlled (electro-hydraulic control) bypass system is designed to control reactor pressure whenever the turbine throttle valves are not able to maintain control. This includes startup and shutdown operations. The bypass system possesses an emergency open mode of operation in which the bypass valves are opened at a full-stroke rate equal to the full-stroke, trip- closure rate of the high-pressure turbine-stop and throttle valves.

The bypass system control logic is designed with triple redundant channels to be compatible with the English Electric (EE) philosophy used on the turbine-governor portion of the system. Each of the two bypass valves operates independently and each has its own self-contained hydraulic (unitized actuator) system. Each valve is sized to pass a nominal 11.75 percent rated reactor flow in the full-open position for a controlled total bypass of 23.5 percent rated reactor flow. The system is designed so that any postulated failure will not cause both valves to fail to open in the fast-opening mode of operation coincident with the closure of the turbine-stop or throttle valves. The controlled bypass failure analysis is discussed in Subsection 10.4.4.4.3 and the failure mode and effects analysis is presented on a systems basis in Table 10.4-1.

10.4.4.4.2 System Description

The pressure control system used on Fermi 2 is a solid-state electronic system, designed by English Electric Company Elliot Automation. The system is a three-channel design operating with a two-out-of-three logic. A simplified sketch of the pressure control system is shown in Figure 10.4-3. The positioning of each bypass valve is achieved by using an individual, unitized actuator for each valve. Each module of each channel has its own power supply, which is connected to two independent ac sources. Each module power supply can use either source to supply its requirements. Consequently, a fault in one module cannot affect the other module power supplies.

The total power requirement for the governor/pressure control system (approximately 2.5 kVA) is supplied entirely by twenty- nine ±15-V dc and three ±5-V dc power supplies. Each of these supplies provides operating potential for one module/control function such as a bypass valve control module. These precision-regulated power supplies are not interconnected with the other module supplies and are fed from redundant and independent 110-V ac power feeds.

The sources for these two independent power feeds are the reactor pressure system buses A and B, which would supply ac power to the system following a loss of offsite power for a period of at least 2 sec. Isolation within a power supply is accomplished using diodes, and each redundant portion of an individual supply is sized to carry the entire module power requirement. A loss of either ac power feed to an individual power supply is alarmed in the control room.

A 480-V ac supply is provided for each valve actuator oil pump. These feeds are common from one power supply. The oil pumps operate in an on-off fashion to replenish the hydraulic accumulators in the actuators as demand dictates.

The 130-V dc power supply that energizes the valve actuator solenoid valves is supplied from the plant battery system. All the turbine valves and the bypass valve solenoids are supplied by BOP battery.

Referring to Figure 10.4-3, in each pressure module the pressure signal from the associated pressure transmitter is compared with the pressure-regulator setpoint. The resulting difference is the pressure error signal. The pressure error signal is operated on by the control algorithm of the pressure regulator and steam line resonance filter to produce a pressure demand signal.

The pressure demand from each pressure regulator is auctioneered against the other demands in three independent, high-value gates. This results in the selection of the pressure demand that will produce the largest bypass valve flow demand. The output of each of the three gates is modified by the flow limiter, which is adjustable and consists of a three-gang potentiometer. The resulting signal is the pressure-steam signal, which is transmitted to the three computing channel modules. At this point, each signal is compared on a per-channel basis in a low-value gate with the other signals controlling the turbine-stop, throttle, and intercept valves.

The low-value gates send the lowest signal back to the pressure control modules. A turbine and/or generator trip sets the low- value gates to a minimum, which results in the generation of a large, opening-demand signal at the input to each of the bypass valve control modules. This error signal is sent from each pressure module and the pressure control module to the input- averaging amplifier of each bypass valve control module. The input amplifier in the bypass valve module averages the three signals and detects and removes any signal that deviates from the average.

The average-demand signal is compared to the actual bypass valve position as measured by redundant valve position transducers (LVDTs) to generate a control signal to drive the bypass servovalve through a power amplifier. The spool valve of the servovalve is mechanically biased to open the bypass valve if the control current through the servovalve is zero. A position-error detection circuit is provided to activate the fast-opening mode of operation when the bypass valve position error (in the open direction) exceeds approximately 8 percent. A contact from the comparator output relay energizes the fast-opening solenoid valve (c) shown in Figure 10.4-4. The solenoid valve allows high-pressure oil from the accumulators to operate the fast- opening valve. The fast-opening valve admits high-pressure oil directly into the bypass valve servocylinder to achieve an opening time of 0.2 sec for full stroke.

An independent one-out-of-two-times-two condenser pressure logic also interfaces with the close solenoid of each actuator to trip the valves closed on low condenser vacuum. When the fast-opening solenoid and the close solenoid are operated at the same time, the close solenoid will override the fast-opening solenoid, and the bypass valve will close. The station battery powers the control solenoids on the bypass valve unitized actuators. Alarms are provided on loss-of-actuator pressure, pressure-module failure, pressure-control-module failure, computing-channel failure, excessive valve-position error, power-supply failure, low fluid level, LVDT failure, or a single condenser switch failure.

10.4.4.4.3 Controlled Bypass Failure Analysis

Due to the redundancy of the control logic and the hydraulic actuator hardware, no identified hardware failure can result in the fast closure of the turbine stop and/or throttle valves and prevent the fast opening of both the bypass valves. In addition, external failures such as loss of condenser vacuum have been considered. A protection logic using separate and redundant condenser-pressure trip strings for both turbine-trip and bypass-trip functions has been provided. The trip setpoint for closure of the turbine control valve and stop valve occurs at a much lower condenser pressure than the bypass valve condenser pressure trip. This allows ample time for the fast opening of the bypass valves to mitigate the effects of the fast stop and/or control valve closure during a condenser vacuum loss.

The control power for the stop and control valve unitized actuators is separate from the bypass valve control power, thereby preventing a single battery failure from closing all the valves through the loss of power to the trip solenoids.

In the unlikely event that all offsite power is lost, the turbine stop and throttle valves will close in the fast closure mode. The bypass system will function in the fast opening mode as intended in this situation. Each unitized actuator has two accumulators that store enough hydraulic energy to stroke each valve approximately three times. Battery control power is provided for the critical control solenoid valves and a supply of ac power to the pressure control module is provided for the duration of the transient. Refer to Table 10.4-1 for a summary of EHC- controlled bypass failure mode and effects analyses.

10.4.4.4.4 Transient Analysis

To exhibit an additional degree of conservatism for the turbine- trip transient analysis, it is assumed that one of the redundant bypass valves fails to open in the fast mode and therefore credit has been taken for only one-half of the controlled bypass capability. The one bypass valve is analyzed with an opening delay of 0.1 sec and a full-stroke time of 0.2 sec. The capacity of one valve at full-open is a nominal 12-1/2 percent rated steam flow.

10.4.5 Circulating Water System

10.4.5.1 Design Bases

The circulating water for cycle heat rejection from the main condenser is provided by a closed cycle circulating water system using two parallel natural draft cooling towers. The cooling towers remove the design heat load from the circulating water for all weather conditions.

10.4.5.2 System Description

The circulating water system supplies the main condenser with the necessary cooling water at temperatures ranging from nominal 55°F to 94°F. In the winter, the water temperature may be as low as 35°F; however, if that is the case, the cooling towers are bypassed. The system consists of the main condenser, cooling towers, circulating water reservoir, and circulating water pumps, as shown in Figure 10.4-5. Data on specific components are given in Table 10.4-2.

The circulating water reservoir is sized to support limited operation of Fermi 2 following loss of makeup water, which might occur with simultaneous conditions of sustained strong westerly winds and low Lake Erie water level, or damage to or blockage of the intake structure. The reservoir base area is nominally 5.5 acres. Approximately 23 x 10^6 gal are available at sufficient head for the circulating water pumps and are sufficient for the evaporative losses expected during a limited period of operation and plant shutdown. Following this, if makeup water is still not available, approximately 7.9 x 10^6 gallons would still remain in the reservoir to supply general service water (GSW) following shutdown of the circulating water pumps.

Five 20 percent (180,000 gpm each), motor-driven, vertical, wet- pit circulating water pumps are located in the circulating water pump house. These pumps take suction from the circulating water reservoir and discharge the circulating water via two 12-ft- diameter pipes to the main condenser where the water temperature is raised 18°F (nominal). The heated water is discharged from the two outlet water boxes into two circulating water pipes, which are 12 ft in diameter and are interconnected so that a cooling tower may be removed from service during operation.

The natural draft cooling towers are designed for a wet-bulb temperature of 74°F. The design range and the design approach are both 18°F. The design range and design approach may vary slightly due to the installation of wind vanes and replacement fill which improve performance under wind conditions. ("Range" is the amount the water is cooled. "Approach" is the difference between cooled water temperature and air wet-bulb temperature.) Each tower is approximately 450 ft in diameter at the base; the maximum elevation is 400 ft above the grade elevation.

After passing through the cooling tower fill, the circulating water flows into the circulating water reservoir and then to the circulating water pump house located at the south end of the reservoir.

A decanting blowdown system is provided on the circulating water system. This is required to maintain water quality because the evaporative process in the cooling tower tends to increase the dissolved solids content in the circulating water. Blowdown (approximately 10,000 to 30,000 gpm) is taken from the circulating water reservoir by one, two, or three decanting pumps, monitored, and discharged to Lake Erie through the 36-in.-diameter decanting line.

A makeup water system replaces the circulating water losses caused by evaporation and blowdown. Makeup water is fed into the circulating water system from the GSW system discharge or from the circulating water makeup pumps (normal and standby). Approximately 22,000 to 28,000 gpm of makeup water are required, depending upon the season of the year.

A biocide can be added to the circulating water to prevent growth of algae and slime on the inner surfaces of the condenser tubes. Regular monitoring of residual halogens at the decanting line is done to comply with environmental regulations. The biocide injection system and dehalogenation system are shown in Figure 10.4-6. A chemical scale inhibitor that has been evaluated to be compatible with materials in the Circulating Water System is added to minimize formation of scale on internal system surfaces. Sulfuric acid is added as needed to adjust the system pH.

The circulating water system is designed with cross-connected discharge piping from the circulating water pumps. The pumps are equipped with separate butterfly valves that permit any circulating water pump or pumps to be isolated while the remaining pumps continue to operate.

Appropriate valving allows the plant to operate on one train of condenser water boxes (one longitudinal half of the condenser can be taken out of service). The system piping is designed in accordance with ANSI B31.1.0.

Cooling water pumps are tripped on high pressure to prevent over-pressurization of the 12-ft lines. Relief valves are provided at the cooling towers to prevent overpressurization by the GSW system.

10.4.5.3 Safety Evaluation

The closest cooling towers are located at least one tower height away from the NSSS containment and auxiliary and turbine buildings complex. It is extremely unlikely that the towers will collapse because they were designed for a wind velocity of 90 mph. If a cooling tower were to collapse, however, it would fall inward, because its base is wider than its top. Therefore, the potential for the debris to damage any plant structure is minimal.

Circulating water is not required for safe shutdown of the plant.

The potential for water hammer in the circulating water piping and the associated rupture of expansion joints has been minimized by using motor-operated valves in place of fast-acting hydraulic or pneumatic positioners. A postulated rupture of the expansion joint in the system may flood the basement of the turbine building; however, even this would not result in any risk to the health and safety of the public because there is no engineered safety feature equipment located in the turbine building.

The reactor/auxiliary building houses safety-related components and is designed against site flooding to Elevation 588 ft, as described in Subsection 2.4.2.2.2. It would therefore withstand turbine building flooding to first floor and grade Elevation 583 ft, at which point the water would run out of the building.

Even though flooding of the turbine building does not pose a safety threat, the following additional information has been provided to describe some aspects of such an event.

First, if the failure were to occur in a circulating water line because of a pressure surge, that same surge would probably trip off the circulating water pumps by means of the pressure switches that protect the system. Flooding would thus not occur.

Second, if the joint should completely fail in either the 9- or 12-ft-diameter circulating water lines, and the pumps did not trip, water would be forced out the resulting 3.5-in. gap at an estimated rate of about 200,000 gpm and would take about 45 minutes to fill the turbine building to grade level. However, the operator would be made aware of the problem due to variations in process parameters and would trip the circulating water pumps long before flooding to grade level would occur.

10.4.5.4 Tests and Inspections

All active components of the system (except the main condenser) are accessible for inspection during station operation. Cooling tower tests, if deemed necessary, are in accordance with the ASME power test code for atmospheric water cooling equipment, PTC-23.

The circulating water pump house (CWPH) will be sampled every spring and fall for the presence of Mollusks. The Fermi 2 Mollusk Monitoring Implementation and Treatment Plan requires that the inlet and outlet water boxes to the main condenser be inspected during the next scheduled outage following the detection of Mollusks in the CWPH. Also, the inlet and outlet water boxes of the main condenser will be inspected if performance decreases significantly.

10.4.5.5 Instrumentation Application

The condenser shell water boxes are equipped with isolation valves that enable either half of the condenser to be isolated. All isolation valves are operated by remote switches in the main control room. Temperature and pressure are measured at the condenser. Circulating water flow and reservoir level are monitored. Also, analysis of the circulating water for pH, biocide residual, and radioactivity is performed.

10.4.6 Condensate Polishing Demineralizer System

Condensate polishing is performed by a full flow polishing demineralizer of the mixed-powdered-resin type.

10.4.6.1 Design Bases

10.4.6.1.1 Fraction of Condensate Flow Treated

The condensate polishing demineralizer system processes all of the condensate from the condenser hotwell (approximately 10.5 x 10^6 lb/hr at full load). The heater drains are pumped forward from the No. 5 heaters to the feedwater stream and are not demineralized (approximately 4.3 x 10^6 lb/hr at full load). These drains, however, are continuously recycled and deaerated to less than 70 ppb dissolved oxygen prior to forward pumping. They are also continuously monitored for oxygen and conductivity to provide additional assurance of no adverse impact to final feedwater quality. Turbidity is monitored on an as-needed basis by local grab during periods when corrosion product concentrations are expected to be higher than normal.

10.4.6.1.2 Effluent Impurity Levels To Be Maintained

Operating procedures ensure that the effluent from the condensate polishing demineralizer system results in reactor impurity levels that meet the requirements of Regulatory Guide 1.56 (see Subsection A.1.56). Further limits on condensate composition and electrical conductivity are established in GE Specification 22A2707, BWR Plant Requirements, Part 7, Water Quality.

The condensate polishing demineralizer maintains the required purity of feedwater flowing to the reactor. During normal operation, the system removes dissolved and suspended solids from the feedwater and maintains a high effluent quality based on the following design values:

a. Specific conductivity (µmho/cm) at 25°C ≤ 0.1

b.	pH at 25°C	6.5 to 7.5
c.	Metallic impurities, as the metal (ppb)	≤ 10 (of which copper shall not exceed 2 ppb)
d.	Silica, as SiO_2 (ppb)	≤ 5
e.	Chloride (ppb)	≤ 2

The limit of metallic impurities in the feedwater measured at the outboard isolation valve is 15 ppb, including a maximum of 2 ppb of copper. During initial plant testing and startup, the normal limit of metallic impurities may be exceeded for the first 500 hr of effective full-power operation. During such a period, the average concentration of metallic impurities shall not exceed 50 ppb at greater than 50 percent power, nor shall it exceed 100 ppb at less than or equal to 50 percent power.

During restarts or periods of operational disturbance, the normal limit of 15 ppb may be exceeded for up to 14 days in any 12-month period. However, the average concentration during this period shall not exceed 50 ppb.

10.4.6.1.3 Design Codes

The condensate cleanup system pressure vessels are constructed in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section VIII, Division I. All piping is in accordance with the ANSI B31.1.0 Code for Pressure Piping.

10.4.6.2 System Description

The condensate polishing-demineralizer system is shown in Figure 10.4-7. It consists of eight parallel-operating demineralizers. Normally, all eight demineralizers are in operation except when one is in backwash/precoat or down for maintenance. The number of demineralizers in service may be varied to accommodate the varying differential flow and pressure requirements of the system. The system includes the associated piping, effluent strainers, backwash, precoat system (with backwash tank and pumps), as well as the necessary valves, instrumentation, and controls required to provide proper operation and protection against malfunction.

The body feed system (with body feed tank pumps) has been abandoned in place and no longer in service.

Instrumentation includes an automatic flow-balancing control that can be used to maintain equal flow (approximately 3000 gpm) through each onstream unit. The valves, pumps and flow can also be controlled manually from local panels.

In the event that a high pressure differential occurs across the condensate cleanup system, an automatic bypass valve opens to prevent damage to the demineralizer. It is highly unlikely that the bypass valve will open during normal operation. However, if this were to occur, appropriate steps would be taken to minimize the introduction of untreated water to the reactor.

10.4.6.3 Safety Evaluation

The condensate demineralizers provide high purity water to the reactor pressure vessel (RPV). Any loss of performance of the demineralizers would be immediately detected by process instrumentation. Buildup of impurities in the RPV is restrained by Technical Specifications limits such that the reactor is shut down well before unacceptable limits are reached. Additionally, more conservative limits and corrective actions are maintained and administered by the plant chemistry section. Subsequent safe shutdown of the reactor does not require the condensate demineralizers.

Resins are not regenerated at Fermi 2. However, they are replaced before the differential pressure of an individual demineralizer or the conductivity of a demineralizer effluent reaches detrimental levels. The alarm setpoint for the influent conductivity meter is 0.2 μS/cm. At this point, the plant chemistry section is notified to acquire samples of influent to check the possibility of a condenser leak. If analysis indicates that a leak exists, corrective action is taken before the 0.5 μS/cm high-high alarm is reached. The alarm setpoints for the effluent conductivity meter are 0.1 and 0.09 μS/cm for the individual and the combined demineralizer outlet, respectively. Corrective action is initiated at 0.1 μS/cm but before 0.2 μS/cm for all individual demineralizer effluents.

The conductivity meter in the condensate cleanup system will be calibrated by comparing it with an in-line laboratory cell once a week. The flow rate through each demineralizer is measured at the outlet from the pressure drop across an orifice plate.

The initial total capacity of condensate polishing and reactor water cleanup demineralizer resins will be measured at least once per year before demineralizer vessel loading. Capacity determinations will be performed by one of the following:

a. Plant Chemistry Section, Fermi 2

b. Engineering Services Organization, Edison

c. Resin vendor/supplier.

The chemistry performed to determine the total resin ionic capacity is outlined by ASTM D-2187. If the type or the supplier of cation and anion resins is changed, a measurement of initial total capacity will be performed before vessel loading. Excess capacity exists in the condensate treatment system to provide for the orderly shutdown of the reactor in the event of a postulated condenser leak of 50 gpm.

The condensate quality guidelines of condensate influent, effluent, final feedwater, and reactor water are summarized in Table 10.4-3.

10.4.6.4 Tests and Inspections

The condensate polishing demineralizer system is tested and inspected in accordance with ANSI N18.7.6 and applicable sections of Regulatory Guide 1.68. All pressure vessels and piping are hydrostatically tested at a pressure 1.5 times the design pressure. Additionally, before the equipment was put into service, a performance test was run to ascertain that the equipment is performing according to the specifications.

10.4.6.5 Instrumentation Application

The performance of the condensate polishing demineralizer system is monitored by conductivity instrumentation at the inlet and outlet and downstream of each demineralizer. Small condenser leaks as low as 6 gpm will be detected. Other instrumentation on the feedwater and reactor water checks for dissolved oxygen, pH, and conductivity. Differential pressure measurements are made to detect solids buildup on the filtering elements. Both local alarms and main control room alarms alert the plant operators whenever undesirable limits are reached. The alarm setpoint at the inlet of the demineralizers in the condensate system is 0.2 μS/cm, and the setpoints for the individual and overall demineralizer outlet are 0.1 and 0.09 μS/cm, respectively.

10.4.7 Condensate and Feedwater System

10.4.7.1 Design Bases

The condensate and feedwater system provides a dependable supply of feedwater to the NSSS, provides feedwater heating, and maintains high feedwater quality. The system provides the required flow at the required pressure to the NSSS and allows sufficient margin to provide continued flow under anticipated transient conditions.

10.4.7.1.1 Performance Requirements

The system provides feedwater at a nominal pressure of 1173 psia from the two RFPs. It has sufficient capacity with appropriate margin to provide feedwater flow for the unit design-basis rating. The feedwater heaters provide feedwater at the required temperature to the NSSS with six stages of closed feedwater heating. The final feedwater temperature is 426.5°F at 100 percent reactor flow.

10.4.7.1.2 Feedwater Quality

Feedwater quality limits are established to prevent adverse effects to fuel, material integrity, and equipment performance. Corrosion product generation/transport and chemical intrusions are controlled and minimized so that a suitable environment is provided for high reliability of plant components.

During startup, condensate is recirculated to the main condenser hotwell until water quality specifications are met. The recirculation line is located downstream of the high-pressure feedwater heaters, and thus full-cycle recirculation is accomplished prior to introduction to the reactor. Guidelines for feedwater quality are listed in Tables 10.4-3 and 10.4-4.

Operating practices limit the conductivity of purified condensate during power operation to the reactor vessel to 0.07 μmho/cm. The control program for dissolved and suspended solids, including sampling frequency and chemical analysis, is described below.

Suspended and dissolved-solids samples are part of an integrated on-line sample collection, which consists of collecting both filterable and dissolved species in one filter housing that contains a membrane filter and ion exchange filter. The on-line filters are checked routinely for flow rate. Integrated on-line samples for feedwater are collected continuously during operation. There are three sample collection intervals weekly.

Filters collected are analyzed for certain metals necessary to conform to fuel warranty specifications. Metal species of interest are typically iron (Fe), copper (Cu), nickel (Ni), chromium (Cr), and zinc (Zn).

Suspended-solids samples are acquired by grab sampling for qualitative analysis by filter color comparison during periods when corrosion product concentrations are expected to be higher than normal.

Control program limits are imposed within the limitations of fuel warranty specifications. Total metals are limited during power operation to <15 ppb with no more than 2 ppb copper.

The basis for these limits is to minimize deposit buildup on fuel heat transfer surfaces and the transport of corrosion products from the core surfaces. Consequently, high heat transfer is maintained, and out-of-core radiation levels are at a minimum.

Zinc is added to the feedwater to control radiation buildup in out-of-core primary coolant piping. The zinc will compete with the cobalt for deposition sites. This will have the end effect of reducing out-of-core radiation dose rates. The additional zinc will add to the dissolved metals and total metals in the feedwater. The amount of zinc to be added to the feedwater is much less than 1 ppb. The zinc will provide the beneficial outcome of controlling radiation build-up on out-of-core surfaces; however, overall metals concentration will still be maintained within the fuel warranty limits to ensure no impact on fuel performance.

Forward-pumped heater drains are untreated and account for approximately 30 percent of total feedwater flow. These drains are monitored for dissolved oxygen and conductivity prior to and during introduction to the feedwater. Turbidity is monitored on an as-needed basis by local grab during periods when corrosion product concentrations are expected to be higher than normal.

10.4.7.1.3 Design Codes

All components of the condensate and feedwater system, except the main condenser and the feedwater piping from the second valve outside the containment to the reactor, are designed and constructed in accordance with the applicable requirements of the following codes:

a. ANSI Code for Pressure Piping, B31.1.0 - Power Piping

b. ASME B&PV Code Section VIII, Division I - Unfired Pressure Vessels.

10.4.7.2 System Description

The condensate and feedwater system consists of the piping, valves, pumps, heat exchangers, controls, instrumentation, and the associated equipment and subsystems that supply the NSSS with heated feedwater in a closed steam cycle using regenerative feedwater heating. The system described in this section extends from the main condenser to the second valve outside the primary containment. The remainder of the system, extending to the reactor, is described in Subsection 5.5.9.

The main portion of the feedwater flow (approximately 70 percent) is condensate pumped from the main condenser. The remaining portion, which comes from the moisture-separator drains, steam reheater drains, and drains from the fifth- and sixth-stage feedwater heaters, is pumped forward from the fifth stage of feedwater heating into the feedwater stream. Turbine extraction steam provides six stages of closed feedwater heating, with the drains from the first four stages of feedwater heating being cascaded through successively lower pressure feedwater heaters to the main condenser.

The condenser pumps take the deaerated condensate from the main condenser hotwell and deliver it through the steam-jet air ejector condensers, the gland steam condenser, and offgas condenser to the condensate polishing demineralizers (see Figure 10.4-8). Demineralizer effluent then passes to the heater feed pumps, which discharge through the first-, second-, third-, fourth-, and fifth-stage low-pressure feedwater heaters to the RFPs.

Additional drain flow comes to the RFPs from the fifth-stage drains, and then is pumped forward and injected into the feedwater stream at the RFP suction header. These drains originate as shown in Figure 10.4-9. The shell drains from the sixth-stage high-pressure feedwater heaters are directed to the shells of the fifth-stage low-pressure feedwater heaters. The shell drainage from the fifth-stage feedwater heaters is collected in the heater drain flash tanks, and then is pumped into the feedwater system by the heater drain pumps.

The RFPs discharge the total feedwater flow through the sixth-stage high-pressure feedwater heaters to the NSSS, as shown in Figure 10.4-10.

10.4.7.2.1 Condenser Pumps

Three condenser pumps operate in parallel (see Figure 10.4-8). Each is a motor-driven, vertical, multistage, centrifugal pump installed at an elevation that allows operation at low condensate level in the main condenser hotwell. The condenser pumps are sized to provide the necessary suction head at the heater feed pumps, even with one condenser pump out of service.

Isolation valves allow each condenser pump to be removed from service individually while maintaining full system capability with the remaining two condenser pumps; however, maintenance must be performed on the pumps during shutdown, with the condenser drained. Condenser pump capacities are given in Table 10.4-5.

10.4.7.2.2 Heater Feed Pumps

Three heater feed pumps operate in parallel (see Figures 10.4-8 and 10.4-9), taking suction from the polishing demineralizer outlet piping and discharging through the low-pressure feedwater heaters. Each is a motor-driven, horizontal, single-stage, centrifugal pump. The heater feed pumps are sized to provide the necessary suction head to the RFPs even with one heater feed pump out of service.

Isolation valves allow each heater feed pump to be removed from service individually while maintaining full system capability with the remaining heater feed pumps. Capacities are given in Table 10.4-6.

Controlled condensate recirculation to the main condenser hotwell is provided downstream of the condensate polishing demineralizer. This ensures that the minimum safe flow through the condenser pumps, steam-jet air ejectors, gland steam condenser, and offgas condenser, is maintained during operation. This recirculation path also provides cleanup during startup since flow is through the demineralizer. Separate minimum flow bypass lines are provided for the heater feed pumps. A Heater Feed Pump (HFP) running signal is taken from the auxiliary contact off of the switchgear breaker feeding each HFP. The use of auxiliary contacts prevents HWC System operation from impacting HFP operation.

10.4.7.2.3 Feedwater Heaters

The first- and second-stage low-pressure feedwater heaters are identically arranged in three parallel streams. The third, fourth, fifth, and sixth stages of feedwater heating are arranged in two parallel streams. The first- and second-stage feedwater heaters are located in the necks of the three steam inlets of the main condenser.

Integral drain-cooling sections are included in the second-, third-, fourth-, and sixth-stage feedwater heaters. External drain coolers are provided for the first-stage heaters and are located on the first floor of the Turbine Building.

Each feedwater heater and drain cooler is of the horizontal, closed type, installed at an elevation that allows proper shell drainage at all loads. Each feedwater heater uses U-tube construction. All feedwater heater and drain cooler tubes are made of stainless steel.

Isolation valves and bypasses allow the feedwater heaters and the drain coolers to be removed from service in groups. System operability is maintained with the remaining feedwater heaters, drain coolers, and bypasses.

The startup and operating vents from the steam side of the feedwater heaters are piped directly to the main condenser. Discharges from shell relief valves on the steam side of the feedwater heaters are piped directly to the main condenser.

10.4.7.2.4 Heater Drain Flash Tank

A heater drain flash tank receives deaerated drainage from the shells of the fifth-stage feedwater heaters. The drain tank provides reservoir capacity for the heater drain pumps suction. The heater drain flash tank is installed at an elevation beneath the fifth-stage feedwater heaters that allows the heaters to drain freely by gravity flow. Remote indicator light is provided to annunciate low tank level switch actuation. When necessary, the fifth-stage heater drains may be diverted to the main condenser instead of the drain tank.

10.4.7.2.5 Heater Drain Pumps

Two one-half capacity heater drain pumps operate in parallel, each taking suction from the heater drain flash tank and discharging to the feedwater stream before the RFPs. A third one-half capacity pump is provided as a spare. Each is a motor-driven, vertical, multistage, centrifugal-type pump located below the heater drain flash tank and designed for the available suction conditions. Nominal sizes, capacities, and other information are given in Table 10.4-7.

The piping arrangement allows a heater drain pump to be removed from service individually while maintaining system operability.

Controlled drain recirculation is provided from the discharge side of each heater drain pump to the heater drain flash tank. This ensures that the minimum required flow through each heater drain pump is maintained during operation at low throughput.

10.4.7.2.6 Reactor Feed Pumps

Two one-half capacity RFPs operating in parallel (see Figure 10.4-10), act in series with the condenser pumps and heater feed pumps and heater drain pumps. The RFPs take suction from the fifth-stage low-pressure feedwater heaters and discharge through the sixth-stage high-pressure feedwater heaters to provide the pressure head required at the NSSS. Each pump is a turbine-driven, horizontal, single-stage, centrifugal unit. Isolation valves allow either RFP to be removed from service individually while maintaining system operability with the remaining RFP. Data for these pumps are given in Table 10.4-8.

Controlled feedwater recirculation is provided from the discharge side of each RFP to the main condenser hotwell. This ensures that the minimum required flow through each RFP is maintained during operation at low throughput.

10.4.7.2.7 Reactor Feed Pump Turbine Drives

Each of the two one-half capacity RFPs is driven by an individual steam turbine. The turbine drives are the dual-admission type, each equipped with two sets of main stop and control valves. One set of valves regulates the low-pressure steam flow extracted from the main turbine hot reheat piping. The other set regulates the high-pressure steam flow from the main steam supply. During normal operation, the turbine drives run on the low-pressure reheat steam. Main steam is used during plant-startup, low-load, or transient conditions when reheat steam either is not available or is of insufficient pressure. The turbine drives exhaust to the main condenser.

Isolation valves allow either turbine drive to be removed from service individually while maintaining system operability with the remaining turbine-driven RFP.

Total turbine output is 14,200 bhp at 4355 rpm with a low-pressure steam pressure of 225 psia and back-pressures of 1.5 in. Hg abs. Further data are given in Table 10.4-9.

10.4.7.3 Safety Evaluation

During operation, radioactive steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping. Shielding and restricted access are provided as necessary (Section 12.1). The condensate and feedwater system is designed to minimize leakage with welded construction being predominantly used. Relief discharges and operating vents from heater shells are treated through closed systems and piped to the condenser. System components are designed for pump shutoff pressures.

The condensate and feedwater system is not required to cause or support the safe shutdown of the NSSS or to perform in the operation of NSSS safety features.

If it is necessary to remove a component such as a feedwater heater, pump, or control valve from service, continued operation of the system is possible by use of the multistream arrangement and the provisions for isolating and bypassing equipment and sections of the system. The isolation capability of the system limits the magnitude of radioactive releases from failed components.

An analysis is presented in Chapter 15 for a feedwater system piping break, which results in the massive leakage of contaminated feedwater directly to the turbine building.

10.4.7.4 Tests and Inspections

During manufacture, shop performance tests on all pumps were carried out. Each feedwater heater, drain cooler, heater drain tank, and pump received a shop hydrostatic test performed in accordance with applicable codes. All tube joints of feedwater heaters and drain coolers were individually shop leak tested. Prior to initial operation, the complete condensate and feedwater system received a field hydrostatic test and inspection in accordance with ANSI N18.7.6 and applicable sections of Regulatory Guide 1.68. Periodic tests and inspections of the system will be performed in conjunction with scheduled maintenance outages.

10.4.7.5 Instrumentation Application

Feedwater flow-control instrumentation measures the feedwater flow rate from the condensate and feedwater system. This measurement is used by the feedwater control system that regulates the feedwater flow to the NSSS to meet system demands. The feedwater control system is described in Sections 7.1 and 7.7.

Instrumentation and controls are provided for regulating pump recirculation flow rate for the condenser pumps, heater feed pumps, and RFPs.

Measurements of pump suction and discharge pressures are provided for all pumps in the system.

Sampling means are provided for monitoring the quality of the final feedwater, as described in Table 9.3-1.

In the feedwater heating portion of the system, temperature measurements are provided for each stage of heating. Steam pressure measurements are provided at each feedwater heater.

Instrumentation and controls are provided for regulating the heater drain flow rate in order to maintain the proper condensate level in each feedwater heater shell or heater drain tank. High-level alarm and automatic emergency drain action on high level are also provided.

A feedwater flowrate signal is taken from the Feedwater Flow Loop and isolated to prevent HWC equipment from affecting the loop. The circuit is similar to the Integrated Plant Computer System (IPCS) input circuit, which is already used in this loop.

10.4.8 Standby Feedwater System

10.4.8.1 Design Basis

The standby feedwater (SBFW) system provides condensate from the condensate storage tank to the feedwater system downstream of the No. 6 feedwater heater. It is a manually initiated system to provide additional assurance of the capability to maintain reactor core cooling and to prevent the uncovering of the core. No credit for the SBFW system has been assumed in the accident analyses in Chapters 6 or 15. The system may be initiated by the control room operator in response to an operational transient, e.g., loss of normal feedwater. This minimizes demands on other high-pressure core cooling systems. The system is not safety related and is nonseismic.

10.4.8.2 System Description

The SBFW system consists of piping, valves, pumps, motors, controls, instrumentation, and associated equipment that supply the feed- water system with condensate from the condensate storage tank. There are two SBFW pumps with a nominal capacity of 1300 gpm and 1247 psig. Each pump is driven by a 700-hp motor; the motors are independently fed from the SS64 and SS65 transformers. The pumps discharge to two parallel motor-operated (dc) modulating flow control valves. The larger valve (6 in.) is used when reactor pressure is near 1120 psi; the other (4-in.) valve is used when reactor pressure is low. There is a motor-operated (dc) isolation valve before tying into the feedwater system. This valve will automatically open when either pump is started and will close at RPV Level 8. The system diagram is shown in Figure 10.4-11.

10.4.8.3 Safety Evaluation

The SBFW system is not required to support the safe shutdown of the reactor except for its use in the alternate shutdown system to meet 10 CFR 50, Appendix R, Section III.L. See Subsection 7.5.2.5. (Inadvertent initiation of the system is bounded by the inadvertent high-pressure-coolant-injection (HPCI) transient, discussed in Subsection 15.5.1, since HPCI flow is approximately five times SBFW flow.)

10.4.8.4 Tests and Inspections

Normal manufacturer's tests were performed on the SBFW pumps and motors. Prior to initial operation, the system received a field hydrostatic test and inspection in accordance with ANSI N18.7.6.

10.4.8.5 Instrumentation Application

Controls are located in the main control room. Measurement of pump discharge flow is provided in the main control room. Pump, motor bearing, and winding temperatures are displayed and alarmed in the main control room.

10.4.9 Zinc Injection System

10.4.9.1 Design Basis

The zinc injection system is designed to allow Fermi 2 to continuously inject a dilute solution of zinc oxide into the reactor feedwater system. Zinc has been shown to reduce radiation fields coming from various primary coolant pipes (primarily in the drywell) by competing for the sites that ^{60}Co would occupy. The system utilizes the differential pressure developed across the reactor feed pumps to provide motive force for the system and is completely manual. It is designed with a low flow bypass line in order to prevent thermal shock.

The zinc injection system is nonsafety related, QA level Non-Q, seismic category none. The system and associated piping and valves meet ANSI B31.1 requirements. The piping and components connected to the reactor feed pump discharges are designed for 1750 psig and 450ºF. The piping and components connected to the reactor feed pump suctions are designed for 950 psig and 430ºF. The dissolution column is designed to hold enough sintered zinc oxide pellets to last a fuel cycle.

10.4.9.2 System Description

The zinc injection system consists of piping, valves controls, instrumentation, and associated equipment that dissolves a dilute solution of zinc oxide into the reactor feedwater system. The system is provided water from the discharge of one of the reactor feed pumps through connections on the pumps minimum flow lines. It enters the skid and passes through a flow straightening vane to ensure a fully developed flow. The flow is measured by a local flow element and then passes through the dissolution column. Dissolution column vessel temperature is measured locally by a thermometer attached to the dissolution vessel. Temperature is measured so that the vessel is not opened for maintenance until it has cooled sufficiently. Flow passes through an outlet strainer which prevents large particles of sintered zinc oxide from entering the feedwater stream. The differential pressure across the column and strainer is measured by a local ΔP indicator. The solution then exits the skid through a manual flow control valve and is returned to the suction of the reactor feedwater pumps. The system flow is manually controlled between zero and 100 gallons per minute. It is based on reactor water zinc concentrations. Zinc dissolution rate is controlled by flow through the vessel, by feedwater temperature, and by the amount of zinc pellets in the column.

To prevent thermal shock of mechanical components and the zinc oxide pellets, a low flow, heat up, bypass loop is provided around the main flow control valve. This bypass loop has a filter that will prevent small zinc oxide pellet fragments or other particles from lodging in the bypass flow control valve. The skid is provided with vents, drains, and test connections for maintenance purposes. Skid isolation valves are also provided. No pumps are installed in the system. All valves are manual and all instruments are local indication only. Therefore, the new system is passive and has no active components. The skid is bolted to the floor on the southeast corner of the TB-1 steam tunnel near column N-3. The system diagram is on drawing M-2012.

10.4.9.3 Safety Evaluation

The zinc injection system is not required for safe shutdown or operation of the reactor. The zinc injection system is not required for plant operation. The addition of this new system does not change the operation or function of the condensate or feedwater systems.

10.4.9.4 Tests and Inspections

The manufacturer performed testing to verify that the equipment operated prior to shipment. They also perform a hydrostatic test of the skid equipment. Prior to initial operation, the system received a pressure test, instrumentation calibration check, and system flow testing.

10.4.9.5 Instrumentation Application

All indications are local. There is local flow indication on the zinc skid for better control of zinc injection rate. Differential pressure indication for the dissolution vessel and outlet strainer is provided to indicate when strainer cleaning or dissolution vessel basket maintenance is required. The dissolution column vessel has local temperature indication provided such that the vessel is not opened for maintenance before the water has cooled to less than 212°F. All system control is local. There are no indications or controls in the control room.

10.4.10 Hydrogen Water Chemistry (HWC) System

10.4.10.1 Design Basis

The purpose of the Hydrogen Water Chemistry (HWC) system is to inject hydrogen into the feedwater system at rates sufficient to allow the noble metal applied to stainless steel reactor vessel internals surfaces to control intergranular stress corrosion cracking (IGSCC) of the vessel internals. IGSCC control is accomplished by the addition of H_2 gas to the final feedwater in an effort to reduce the dissolved O_2 concentration due to the radiolytic decomposition of water in the reactor core. By reducing the O_2 concentration in the reactor water, the corrosion potential of the water is reduced.

With a few exceptions, the HWC system has been designed in accordance with the BWR Owners Group "Guidelines for Permanent BWR Hydrogen Water Chemistry Installation - 1987 Revision" (Reference 4). The HWC system is designed to meet the following design bases:

1. To supply hydrogen for feedwater injection at rates up to approx. 7-15 scfm, which corresponds to feedwater concentration of approx. 0.14 – 0.31 ppm.
2. To supply oxygen to the Off-Gas system at a rate equal to 50% of the hydrogen injection rate to ensure a stoichiometric mixture for recombination of hydrogen and oxygen.
3. To supply oxygen into the Condensate system to keep the oxygen levels in the condensate and feedwater systems high enough to minimize general corrosion.
4. To automatically isolate hydrogen and oxygen injection in the event of system or component failures.

The HWC System injects sufficient hydrogen into the feedwater system to allow the noble metal applied to stainless steel reactor internal surfaces via the On Line NobleChem (OLNC) System to catalytically recombine oxygen and hydrogen peroxide in the reactor coolant. OLNC is a technology developed by General Electric (GE) for applying noble metal to stainless steel reactor internals. This technology has successfully reduced the electrochemical corrosion potential (ECP) of internals below -230mV$_{SHE}$ (Standard Hydrogen Electrode). It has been shown that at this ECP and below, IGSCC is successfully mitigated in a BWR.

In addition to the EPRI Guidelines (Reference 4), the HWC system was designed to meet the following codes and standards:

OSHA 29 CFR 1910.103	Hydrogen
OSHA 29 CFR 1910.104	Oxygen
OSHA 29 CFR 1990.119	Process Safety Management of Highly Hazardous Chemicals
NFPA 50, 1990	Bulk Oxygen Systems at Consumer Sites
NFPA 50A, 1994	Gaseous Hydrogen Systems at Consumer Sites
NFPA 50B, 1994	Liquefied Hydrogen Systems at consumer Sites
CGA G-4	Oxygen
CGA-4.1, 1985	Cleaning Equipment for Oxygen Service
CGA G-4.3	Commodity Specification for Oxygen
CGA G-4.4, 1993	Industrial Practices for Gaseous Oxygen Transmission and Distribution Piping
CGA G-5	Hydrogen
CGA G-5.3	Commodity Specification for Hydrogen
CGA G-5.4, 1992	Hydrogen Piping Systems at Consumer Locations

The piping at the Gas Supply Facility is designed to ASME B31.3, Chemical Plant and Petroleum Refinery Piping. The underground yard piping and the piping inside the Turbine Building is designed to the requirements of ANSI/ASME B31.1, Power Piping.

All liquid and gas storage vessels are designed, fabricated and stamped as ASME Boiler and Pressure Vessel Code, Section VIII, Division I, Unfired Pressure Vessels.

System wiring, grounding and cathodic protection is designed in accordance with NFPA 70, the National Electric Code. In addition, lightning protection for the GSF has been designed per NFPA 780-92, "Lightning Protection Code."

10.4.10.2 System Description

The HWC system continuously injects hydrogen gas into the heater feed pump suction to reduce the dissolved oxygen concentration in the Reactor. Oxygen gas is continuously injected into the Off-Gas system at the common 18" manifold to recombine with hydrogen to maintain the stoichiometric balance for recombination. Oxygen gas is also added to the

Condensate system at the condensate pump suction to make up for the reduced oxygen concentration in the condenser. The operating modes of the HWC system are startup, operation, and shutdown. For overall system piping configuration, see drawing 6M721-2013.

Liquid hydrogen is stored in a cryogenic tank at the gas supply facility. The hydrogen is stored under its own vapor pressure until withdrawn by the compressor system. Two 100% capacity parallel compressor trains are provided for system reliability. One compressor operates while the other acts as a backup. The operating compressor withdraws a combination of cold gas from the tank head space and liquid from the tank bottom and compresses it to a pressure several hundred psig above the required pressure. This allows the supply system to preferentially withdraw gaseous hydrogen from the tank head space, reducing system losses. After compression, the hydrogen is sent through ambient air vaporizers which evaporate it to within 20°F of ambient temperature. Each compressor train has two, 100% capacity vaporizers with automatic switching to allow de-icing. Gaseous hydrogen flows to a pressure control manifold which reduces the supply pressure to the operating pressure.

Hydrogen gas then flows via underground piping to the Turbine Building and through piping in the Turbine Building to the injection skid. The injection skid contains a flow element and three injection legs, each equipped with a flow control valve and isolation valve. Each injection leg from the skid is piped to the suction of one of the heater feed pumps. The isolation valve in each injection leg closes on a system shutdown signal, or individually, if the respective pump is tripped. There is a check valve at each heater feed pump suction connection to prevent backflow of water into the hydrogen piping. Each pump suction connection also contains a manual isolation valve and purge connection.

Liquid oxygen is stored in a cryogenic tank at the gas supply facility. The oxygen is stored under its own vapor pressure. Upon demand, oxygen is withdrawn from the tank and passed through an ambient air vaporizer. An economizer circuit preferentially withdraws oxygen vapor from the tank head space, reducing system losses. There are two 100% capacity vaporizers piped in parallel with automatic switching to allow de-icing. Gaseous oxygen flows to a pressure control manifold which reduces the supply pressure to the operating pressure.

Oxygen gas then flows via underground piping to the Turbine Building and through piping in the Turbine Building to the injection skid. The injection skid contains a flow element and two parallel flow control valves. The skid outlet is piped to the common 18” manifold in the Off-Gas system. There is a check valve in the oxygen piping, upstream of the Off-Gas connection, to prevent backflow from the Off-Gas into the oxygen piping. (For system configuration details, see drawing 6M721-2013.)

Oxygen gas is also injected into the Condensate pumps suction common header to make up for the reduced oxygen concentration in the condenser. Injection can be accomplished through the supply piping routed from the gas supply facility, or through an alternate bottled gas station.

Liquid nitrogen is stored at the gas supply facility for use in purging, instrumentation, and valve actuation as required in the design of the gas supply facility. Prior to use, the liquid nitrogen is converted to gas by an ambient vaporizer.

10.4.10.3 Safety Evaluation

The HWC system is non-safety related, QA level non-Q, seismic category none. The electrical components are not Class 1E or environmentally qualified. The HWC system is not required to mitigate the consequences of any accident or malfunction, nor to achieve safe shutdown of the reactor or safe plant operation.

The HWC system has been designed and sited in accordance with the requirements of Reference 1. Where full compliance could not be achieved, technical justification was provided. The liquid hydrogen storage tank is located at a distance greater than 800 feet from the nearest safety related structure (RHR Complex). This separation distance assures that a worst case hypothetical detonation of the liquid hydrogen storage tank will not endanger safety-related structures and equipment. An explosion of the liquid hydrogen tank may cause damage to the roof and siding of the Reactor Building above the elevation of the Refuel Floor, and the roof and siding of the Turbine Building above the elevation of the Operating Deck. However, due to the large separation distance, the force on these structures would be less than those generated by design-basis tornadoes or earthquakes. Therefore, the effects of a hydrogen tank explosion on the upper floors of the Turbine and Reactor Buildings is bounded by the analysis for the design basis tornado.

All hydrogen and oxygen storage vessels have sufficient separation from safety-related intakes in the event of vessel failure without fire or explosion. The liquid hydrogen storage tank and piping over 0.4-inch diameter are seismically designed to prevent failure during a safe shutdown earthquake. The liquid hydrogen and oxygen tanks and the gaseous hydrogen tube banks are designed to remain in place during a design basis tornado, earthquake, or flood so that any releases would originate from that source location. The storage vessels are also designed to be adequately protected from lightning and transportation accidents.

Excess flow protection devices at the gas supply facility and Turbine Building entrance will provide rapid isolation in the event of a line break. Area hydrogen detectors are installed in the Turbine Building near HWC equipment to detect hydrogen leakage and initiate system isolation. Once hydrogen injection is isolated by the system trip signals identified in the section below (Instrumentation and Controls), oxygen injection isolation will lag the hydrogen injection isolation by a pre-set time to ensure the maximum recombination of hydrogen in the Off-Gas system.

10.4.10.4 Instrumentation and Controls

The hydrogen injection rate is initiated with a low flow that is sufficient for establishing IGSCC mitigation during heatup. This rate is maintained until reactor power reaches approximately 25% at which point the injection rate increases proportionally with reactor power level. The oxygen flow is approximately half the hydrogen flow rate. The flow control valve in each injection leg is controlled from a single flow control signal. The flow element on the skid provides feedback to the flow control loop. Once activated, injection will be isolated under any of the following actions/conditions:

a. Manual Shutdown

b. Reactor Protection System Trip

c. Hi-Hi Hydrogen (From Area H_2 Monitor)

d. High Hydrogen Flow

e. Off-Gas Flow Restriction (Valves not Fully Open)

f. Deleted

g. Low Percent Oxygen in Off-Gas

h. High Hydrogen Supply Pressure

i. Deleted

j. Supply Facility Trip

Local instruments are provided at the gas supply facility and at the HWC control panels in the Turbine Building. System shutdown and trouble annunciators are provided in the Control Room. In addition, hydrogen injection enable/trip control is provided in the Control Room.

All signals from safety related circuits are isolated to prevent the HWC system from adversely affecting the operation of safety related systems.

10.4.11 On-Line Noble Chemistry Injection System

10.4.11.1 Design Basis

The On-Line Noble Chemistry (OLNC) Injection System is designed to allow Fermi 2 to inject a dilute solution of platinum or other noble metals into the reactor feedwater system. The injection results in a fine layer of noble metal being deposited onto the wetted surfaces of the reactor and associated piping.

As documented in Reference 6, surfaces with noble metal compound in a low hydrogen coolant environment have been shown to reduce the potential of intergrannular stress corrosion cracking (IGSCC) and mitigate existing IGSCC in the reactor vessel by reducing the electrochemical corrosion potential (ECP). Based on laboratory data, when the ECP is below 230 mV_{SHE}, (SHE = Standard Hydrogen Electrode) IGSCC crack initiation is mitigated and crack growth rates are lowered. Noble metal coating on the wet surfaces of the reactor coolant system piping has been shown to slow or mitigate IGSCC in the reactor vessel and attached reactor coolant system piping. The noble metal penetrates existing cracks to help slow or mitigate crack growth.

The OLNC application is performed after a sufficient time of power operation after a refueling outage to ensure oxide layer is developed on newly inserted fuel assemblies and within the vendor recommended range of power and core flow necessary to ensure adequate noble metal deposition. The online injection results in a more even distribution of metals throughout the system and deeper penetration in to the existing cracks and crevices.

References 5 and 6 evaluated the effects of injection noble metal into the reactor coolant system. The evaluation reviewed effects on the reactor fuel, reactor fuel performance, reactor coolant piping, the Reactor Recirculation System, and the Reactor Water Clean-up System.

The OLNC injection system is non-safety related, QA level Non-Q, seismic category II/I. The system and associated piping and valves meet ANSI B31.1 requirements. The piping and components connected to the reactor fed water system are designed for 1275 psig and 450°F. The system is designed to inject sufficient noble metal solution to reduce the ECP of reactor coolant surfaces below -230 mV_{SHE}, as measured at the mitigation monitoring system in the Reactor Water Clean-up System, when the injected noble metals, the zinc injection system, and the Hydrogen Water Chemistry system work concurrently.

10.4.11.2 System Description

The OLNC injection system consists of piping, valves, controls, instrumentation, and associated equipment that injects a dilute solution of noble metal into the reactor feedwater system. The system pumps solution from a temporarily staged OLNC injection skid on the north-east corner of the Reactor Building First Floor by the steam tunnel entrance. The injection skid is connected to the injection lines viaflexible hose connections. The flow and the injection pressure are indicated at the injection skid.

The injection skid is provided with vents, drains, and test connections for maintenance purposes. Skid isolation valves are also provided. All valves are manual and all instruments are local indication only. Therefore, the new system is passive and has no active components. When not in use, the injection skid will be stored on Reactor Building Third Floor. The system tie-ins to the feedwater system are indicated in Figure 10.4-10.

The Mitigation Monitoring System (MMS) is a one-pass-through system that provides a series of tubing samples to monitor and analyze the amount of noble metal remaining on the tubing interior surfaces, which is representative of the amount of noble metal remaining on the internal surfaces of the reactor vessel during and following an OLNC application. The MMS consists of a Durability Monitor Panel, a Data acquisition System Panel, and an Automatic Flow Control Module Panel. The MMS includes sensors that are installed to measure the ECP of the reactor water.

The MMS skid is provided with vents, drains, and test connections for maintenance purposes. Skid isolation valves are also provided. All valves are manual and all instruments are local indication only. Therefore, the new system is passive and has no active components. The system tie-ins to the Reactor Water Cleanup System are shown in Figures 5.5-19 and 5.5-20.

10.4.11.3 Safety Evaluation

The OLNC injection system is not required for safe shutdown or operation of the reactor. The OLNC injection system is not required for plant operation. The addition of this new system does not change the operation or function of the Reactor Water Clean-up, condensate or feedwater systems.

10.4.11.4 Tests and Inspections

The manufacturer performed testing to verify that the equipment operated prior to shipment, including a hydrostatic test of the skid equipment. Prior to initial operation, the system received a pressure test, instrumentation calibration check, and system flow testing.

10.4.11.5 Instrumentation Application

All indications are local. There is local flow indication on the OLNC injection skid for control of noble metal injection rate. Local indicators are provided on the durability monitor panel for flow and water temperature. All system control is local. There are no indications or controls in the control room.

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

REFERENCES

1. Detroit Edison Letter to the NRC, EF2-57,134, Dated April 27, 1982.
2. The NRC Safety Evaluation Report, NUREG-0798, Supplement 1, dated September 1981, and Supplement 3 Dated January 1983.
3. DECo File No. T14-006, "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", Dated October 18, 2005.
4. EPRI NP-5283-SR-A, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations," 1987 Revision.
5. BWRVIP-143, BWR Vessel and Internals Project, "On-Line Noble Metal Chemical Application Generic Technical Safety Evaluation."
6. DECo File No. R1-8056, GEH OLNC 0000 0099 7942 02 RO, "On-Line NobleChem™ (OLNC) Application Technical Safety Evaluation For Fermi Unit 2."
7. DECo File No. R1-8196, 0000 0155 8335 R1, GEH OLNC evaluation, Dated July 3, 2013.
8. DTE CP 003, DECo File No. T14-006, "Revised RETRAN02 Model for Moisture Separator Reheater for Uprate Conditions", Dated August 30, 2013.

TABLE 10.4-1 EHC-CONTROLLED BYPASS FAILURE MODE AND EFFECTS ANALYSES

SUBSYSTEM: AUXILIARY SYSTEMS

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
1.	120-V ac supply to EHC cabinet	Loss of potential	Fuse failure, short, bus trip	No effect	Alarms on failure	No	No	Load pickup by backup supply feeder
2.	130-V dc battery supply	Loss of potential	Fuse failure, short	Deenergizes both closure solenoids in bypass valve actuators	Alarms, pump duty	Yes	No	Solenoid power supply for turbine valves is obtained from the other plant 130-V dc battery
3.	Actuator cooling water	Loss of flow	Line fails, trip of TBCCW system	Temperature increase in actuator	Alarms on high temperature	No	No	Temperature rise is slow, addition of heat due to pump that is not operating continuously
4.	Condenser	Loss of vacuum	Condenser failure, loss of circulating water, loss of steam-jet air ejectors	Trips bypass and turbine valves closed via actuator solenoids	Alarms on decreasing vacuum; alarms on equipment loss	Yes	Yes	Separate vacuum switch logic with redundant devices is provided for each trip (bypass valve and turbine valve vacuum trips); the setpoint for each trip is different, allowing the turbine to be tripped before the bypass valves are finally tripped as the condenser vacuum is lost
5.	Equipment cabinet environment	Loss of cooling	Loss of fan power, filters plugged, ambient temperature high	Possibly failure system, progressive failure most probable	Alarms on high temperature	Yes	Yes	System has been operated continuously in a test ambient of 40°C as part of acceptance test
6.	Actuator oil pumps	Manual trip of all actuator oil pumps	Operator error	Trip of turbine and bypass valves after 2-minute time delay	Alarms	Yes	Yes	This trip is normally used to lock valve closed during maintenance on turbine

SUBSYSTEM: UNITIZED ACTUATOR

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
1.	Valve control module	Output zero	Electronic failure	Deenergizes solenoid valve	Alarms on failure of module	Yes on one bypass valve	No	None
2.	Valve control module	Position error detector	Electronic failure	Fails to energize solenoid valve	Alarms, test of valve	Yes on one valve	No	None
3.	Bypass valve position transducer (LVDT)	Output zero	Mechanical or electrical failure	Deenergizes solenoid valve	Alarms on failure	Yes on one valve	No	Redundant LVDTs provide check circuit for alarm

TABLE 10.4-1 EHC-CONTROLLED BYPASS FAILURE MODE AND EFFECTS ANALYSES

SUBSYSTEM: AUXILIARY SYSTEMS

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
4.	Control cabling from EHC (valve control module) cabinet to actuator	Shorted or open	Mechanical damage	Renders valve inoperable	Failure obvious	Yes	No	Cabling to bypass valves not common due to physical location of actuator on each valve
5.	Pressure module No. 1, 2, and control module	Output zero	Electronic failure	No effect on operation of valves	Alarms on failure	No	No	Two-out-of-three taken twice analog control logic, failed channel is disconnected from control
6.	Computing channel No. 1, 2, or 3 low value gates	Output saturated	Electronic failure	No effect on operation of valves	Alarms on failure	No	No	Two-out-of-three taken twice analog control logic, outputs of each channel are compared with the remaining two to detect this type of failure
7.	Power supply (any module)	Output zero	Electronic failure	No effect on operation of module	Alarms on failure	No	No	Redundant supplies are provided for each module

SUBSYSTEM: UNITIZED ACTUATOR

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
1.	Servo- cylinder	Leakage	Seal failure	Fast opening of bypass valve not obtained	Level alarm on loss of fluid	Yes on one valve	No effect	Oil line failure not considered, control hardware mounted actuator manifold ports directly
2.	Servo-cylinder	Blockage	Foreign substance in oil	Fast opening of bypass valve not obtained	Test of valve	Yes on one valve	No effect	Each actuator has integral oil supply
3.	Dump valve	Leakage	Foreign substance in valve	Fast opening of bypass valve not obtained	Test of valve	Yes on one valve	No effect	None
4.	Servo-valve	Drain port open	Defect, failure of valve control module	Possibly prevent fast opening of valve	Test of valve	Yes on one valve	No effect	Servovalve is spring biased to admit oil to the servocylinder if the control signal is lost
5.	Accumulator	Loss of nitrogen	Diaphragm leak, valve leak	Reduces stored energy available	Gage readings on each accumulator	No	No effect	Capacity of one actuator is ample for one valve operation
6.	Fast- open valve	Jammed	Defect, leakage, foreign material in oil	Fast opening oil supply not available at the servo-cylinder	Test of hardware	Yes	No effect	None

TABLE 10.4-1 EHC-CONTROLLED BYPASS FAILURE MODE AND EFFECTS ANALYSES

SUBSYSTEM: AUXILIARY SYSTEMS

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
7.	Oil dump solenoid valve	Opens to drain	Loss of dc control voltage, coil open, condenser vacuum trip	Dump valve operates draining oil from servo-cylinder	Alarms on power supply, cycling of oil pump increases	Yes	No effect	Control power for both bypass valve solenoids is independent of control power for turbine valves; condenser vacuum trip logic for bypass valves (1/2) x 2 logic; control power for bypass valve solenoidsis independent of control power for turbine valves
8.	Oil dump solenoid valve	Fails to operate	Loss of dc control voltage, coil open, valve stuck	Fast open valve does not receive operating oil pressure	Alarm on power supply loss, test of circuit	Yes	No effect	None

TABLE 10.4-2 CIRCULATING WATER SYSTEM COMPONENTS

Circulating water pumps

Number	Five
Type	Vertical, wet pit
Capacity (each), gpm	180,000
Head, ft	92

Cooling tower

Number	Two
Type	Natural draft
Design wet-bulb temperature, °F	74
Design range, °F	18*
Design approach, °F	18*
Relative humidity, percent	58
Dimensions, ft	450 x 400 approximately
Design capacity, each	450,000 gpm

* NOTE: The design range and design approach may vary slightly due to the installation of wind vanes and replacement fill which improve performance under wind conditions.

TABLE 10.4-3 CONDENSATE QUALITY GUIDELINES, NORMAL OPERATION

		Influent to Cond. Demin.	Effluent from Cond. Demin.	Feedwater to Reactor	Reactor Water
1.	Specific conductivity at 25 °C, maximum	0.5 µmho/cm[c]	0.1 µmho/cm[c]	0.1 µmho/cm	1.0 µmho/cm[b]
2.	pH at 25 °C		6.5 to 7.5	6.5 to 7.5	5.6 to 8.6[b]
3.	Chloride (as CL^-), maximum				200 ppb[b]
4.	Dissolved O_2		30-50 ppb	200 ppb max. 20 ppb min.	-
5.	Total metallic impurities			15 ppb (max.)[a]	-

[a] No more than 2 ppb copper.
[b] These are limits from Regulatory Guide 1.56, Table 1
[c] These are limits from Regulatory Guide 1.56, Table 2

TABLE 10.4-4 CONDENSATE QUALITY GUIDELINES, STARTUP

	Influent to Cond. Demin.	Effluent from Cond. Demin.	Feedwater to Reactor	Reactor Water
Specific conductivity at 25 °C, maximum	0.5 µmho/cm[e]	0.1µmho/cm[e]	-	2 µmho/cm[a,d] 10 µmho/cm[b,d]
pH at 25 °C			-	5.6 to 8.6[d] 5.3 to 8.6[b,d]
Chloride (as Cl^-), maximum			-	200 ppb[d] 100 ppb [a,d] 500 ppb[b,d]
Dissolved O_2		200 ppb max. 20 ppb min.	-	
Total metallic impurity, maximum		100 ppb (max.)[c]	-	

[a] Steaming rates less than 1 percent of rated steam flow.
[b] Reactor depressurized (<100 °C).
[c] No more than 2 ppb copper.
[d] These are limits from Regulatory Guide 1.56, Table 1.
[e] These are limits from Regulatory Guide 1.56, Table 2.

TABLE 10.4-5 CONDENSER PUMPS

Number	Three	
Type	Vertical	
	Three Pumps, 100 Percent Reactor Flow	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	7130	10,695
Suction temperature, °F	91.7	91.7
Suction pressure, psia	5.37	5.37
Discharge pressure, psia	243	183

TABLE 10.4-6 HEATER FEED PUMPS

Number	Three	
Type	Horizontal, single-stage, double volute	
Manufacturer	Byron Jackson	
Horsepower	3000	
Shaft speed, rpm	3574	
Driver	Westinghouse, horizontal, three-phase, 60-Hz electric motor	
Applicable code	ASME B&PV Code Section III, Division I	
	ASTM A193 and A194 (Nuts and Bolts)	
	ASME Pump Test Code	
	ANSI B1.4 and B18.2 (Nuts and Bolts)	
Location	First floor, turbine building	
	Three Pumps, 100 Percent Reactor Flow	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	7083	10,624
Suction temperature, °F	94.2	94.2
Suction pressure, psia	151	151
Discharge pressure, psia	693	548

TABLE 10.4-7 HEATER DRAIN PUMPS

Number	Three
Type	Vertical, nine stage, centrifugal
Manufacturer	Ingersoll-Rand
Horsepower	1750
Shaft speed, rpm	1780
Driver	Westinghouse, 4000-V, 60-Hz, three-phase
Applicable Code	ASME B&PV Code Section VIII, Division I ASTM A193 and A194 (Nuts and Bolts) ANSI B1.1 and B18.2.1 (Nuts and Bolts) ASME Pump Test Code
Location	First floor, turbine building

	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	5000
Suction temperature, °F	391.6
Suction pressure, psia	225
Discharge pressure, psia	705

TABLE 10.4-8 REACTOR FEED PUMPS

Number	Two
Type	Horizontal, single-stage, centrifugal
	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	17,100
Suction temperature, °F	388
Suction pressure, psia	513
Discharge pressure, psia	1173

TABLE 10.4-9 REACTOR FEED PUMP TURBINES

Number	Two
Type	Horizontal, dual- admission, multistage
	Two Turbines, 100 Percent Reactor Flow
Speed, rpm	4355
Total Output, bhp	14,200
Low-pressure steam pressure, psia	225 125 °F of superheat (h = 1274 Btu/lbm)
Low-pressure steam temperature, °F	517
High-pressure steam pressure, psia	947 Saturated (h = 1190.4 Btu/lbm)
High-pressure steam temperature, °F	538
Total Low-pressure steam consumption, lb/hr	140,000

Figure Intentionally Removed
Refer to Plant Drawing I-2336-05

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 10.4-1

TURBINE GLAND SEALING SYSTEM

FIGURE 10.4-2 HAS BEEN INTENTIONALLY DELETED

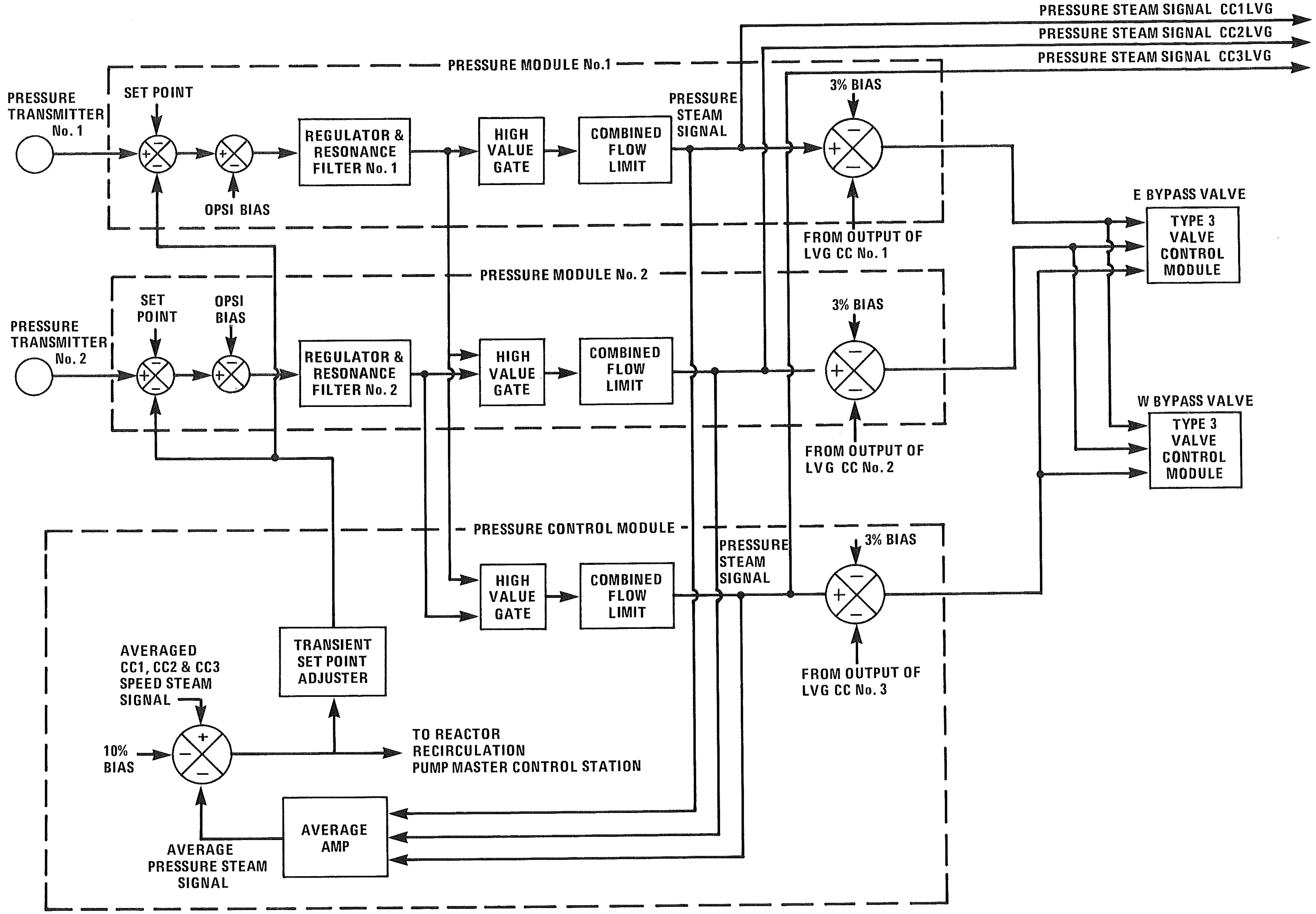

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FIGURE 10.4-3

SIMPLIFIED GOVERNOR/PRESSURE CONTROL BLOCK DIAGRAM

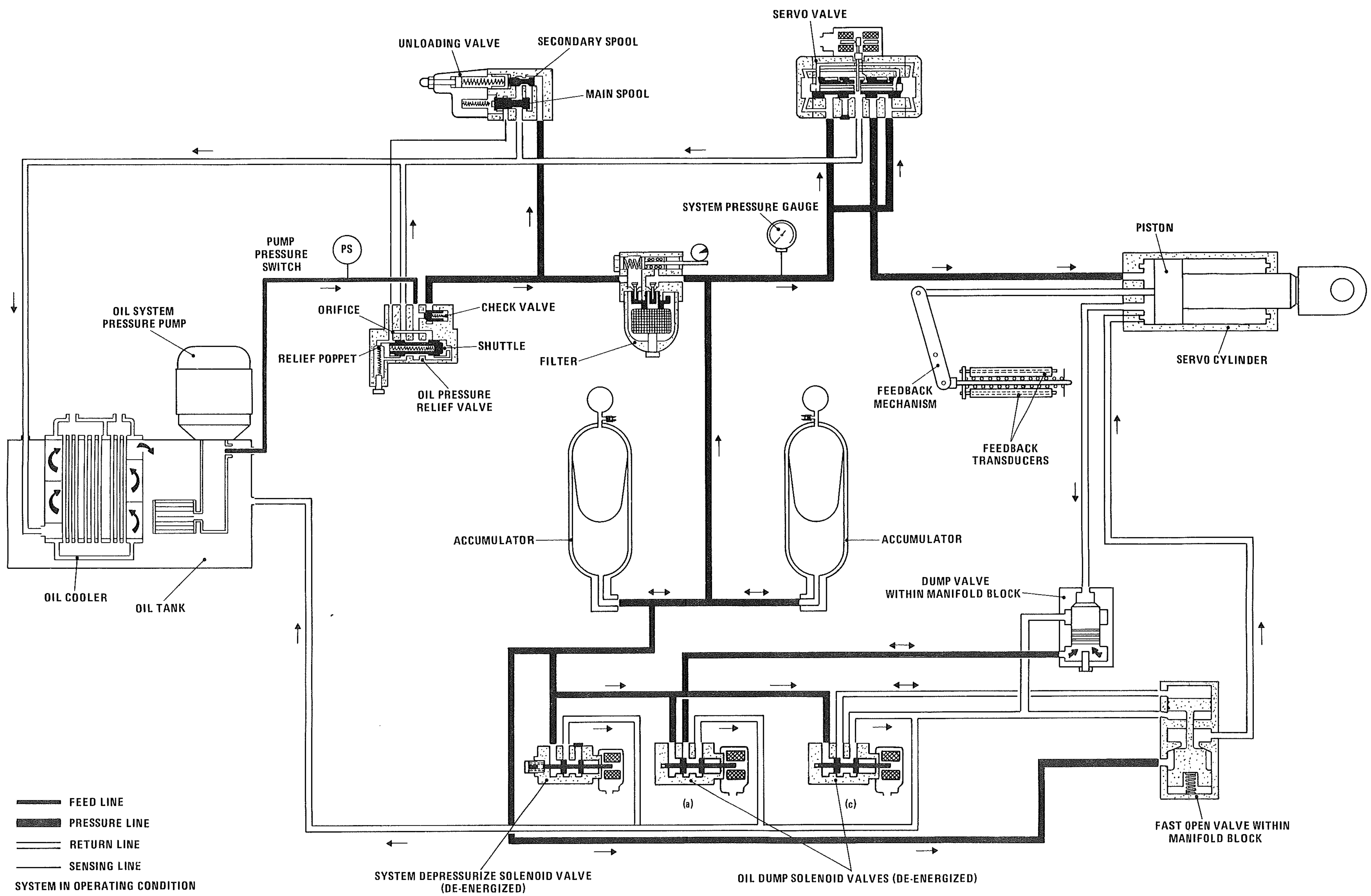

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FIGURE 10.4-4

SERVO OIL SYSTEM BYPASS VALVE ACTUATOR

Figure Intentionally Removed
Refer to Plant Drawing M-2007

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FIGURE 10.4-5

CIRCULATING WATER SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing M-5743

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FIGURE 10.4-6

CIRCULATING WATER SYSTEM
BIOCIDE INJECTION/ DEHALOGENATION SYSTEMS

Figure Intentionally Removed
Refer to Plant Drawing M-2011

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FIGURE 10.4-7, SHEET 1

CONDENSATE POLISHING DEMINERALIZER SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing M-2011-1

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FIGURE 10.4-7, SHEET 2

CONDENSATE POLISHING DEMINERALIZER SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing M-2004

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FIGURE 10.4-8, SHEET 1

CONDENSATE SYSTEMS

Figure Intentionally Removed
Refer to Plant Drawing M-2004-1

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FIGURE 10.4-8, SHEET 2

CONDENSATE SYSTEMS

Figure Intentionally Removed
Refer to Plant Drawing M-2005

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FIGURE 10.4-9, SHEET 1

HEATER DRAIN SYSTEMS

Figure Intentionally Removed
Refer to Plant Drawing M-2005-1

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FIGURE 10.4-9, SHEET 2
HEATER DRAIN SYSTEMS

Figure Intentionally Removed
Refer to Plant Drawing M-2023

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FIGURE 10.4-10

FEEDWATER SYSTEM

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Refer to Plant Drawing M-5083

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FIGURE 10.4-11

STANDARD FEEDWATER SYSTEM
P&ID