SECTION 10

STEAM AND POWER CONVERSION SYSTEM

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SECTION 10

STEAM AND POWER CONVERSION SYSTEM

10.1 GENERAL DESCRIPTION

This section describes the steam and power conversion system which is designed to receive steam generated by the steam generators in the reactor coolant system (Section 4) and to produce electrical power.

The system consists of a closed regenerative cycle in which steam from the main turbine is condensed and returned as heated feedwater to the steam generators.

The performance of the turbine generator at licensed power conditions is depicted on Figure 10.2-1.

10.2 DESIGN BASES

The steam and power conversion system is designed to provide the highest operating economy with maximum safety and availability. The principal design basis is represented by the heat balance calculated at the rated thermal power of the reactor which incorporates all the applicable design considerations for steam and power conversion. The heat balance applicable for operation at the licensed power conditions is shown in Figure 10.2-1.

The unit is normally operated base loaded, but responds automatically to unscheduled changes in load.

Because of the nuclear application of the steam and power conversion system, provisions have been made in safety-related portions of the system for earthquake, tornado and missile protection. Those portions of the system that are safety related are located in the main steam valve cubicle area which is missile, tornado and flood protected. The valve cubicle also contains, in addition to the main steam isolation valves, the main feedwater isolation valves and the steam supply valves for the steam driven auxiliary feedpump.

No equipment contained within the turbine building is required for the safe shutdown of the reactor plant or to mitigate the consequences of an accident. However, the River Water System discharge pipe does enter the turbine building and empties into the circulating water system or, upon operation of valves, flows through a bypass line to the Unit 2 cooling tower blowdown line.

10.3 SYSTEM DESIGN AND OPERATION

10.3.1 Main Steam System

The main steam system is shown schematically in Figures 10.3-1 and 10.3-2. At 2,910 MWt, the output rating of the Nuclear Steam Supply System, the turbine generator gross output is as depicted on Figure 10.2-1.

10.3.1.1 Design Basis

The main steam system piping and fittings have been designed, fabricated, welded, inspected and accepted in accordance with the American National Standards Institute (ANSI) B31.1-1967, Code for Pressure Piping, including addenda through June 30, 1971. Welding during the Operations phase may be performed in accordance with the ANSI B31.1 Code 2001 Edition.

The main steam safety valves were designed and fabricated in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III Article 9, Protection Against Overpressure. Examination and inspection requirements applied were those specified by the Code.

Flanges of the valves were fabricated in accordance with ANSI B16.5, Steel Pipe Flanges and Flanged Fittings.

Installed piping was hydrostatically tested to 1.5 times the maximum operating pressure as required by ANSI B31.1. The safety valves were tested using required steam line pressure along with a hydraulically assisted testing rig approved by the code.

The performance of the main steam system is shown in Figure 10.2-1. The main steam system is designed for 1,100 psig and 560°F.

The following piping and equipment of the main steam system are designed as Seismic Category I (Appendix B):

1. Steam generators and supports
2. Main steam piping, valves, safety valves and supports from the steam generators to and including main steam trip and nonreturn valves
3. Steam piping from main steam lines to the decay heat release control valve and to the turbine drive for the turbine-driven steam generator auxiliary feedpump.

The main steam piping supports are analyzed for turbine trip forces, main steam trip valve forces and in accordance with the seismic criteria. In addition, the system is stress analyzed for the forces and moments which result from thermal growth. The main steam piping within the containment annulus is analyzed for possible pipe rupture and sufficient supports and guides are provided to prevent damage to the containment liner and adjacent piping. In addition, the safety valves and connecting piping have been analyzed for the dynamic forces imposed during steam relief. Main steam system supports and piping from the steam generator nozzles to the first isolation valve outside of containment have also been analyzed for water intrusion into the affected main steam line, associated with a tube rupture event. This condition can occur due to overflow of the steam generator resulting in water intrusion into the main steam line. Only

stresses due to deadweight, pressure and thermal expansion effects were considered. The analysis assumed a system temperature and pressure of 560°F and 1100 psig respectively, and concluded that the main steam piping and supports between the steam generators and the first isolation valve outside of containment have the capability to support flooded lines.

Missile protection of the atmospheric dump valve (ADV), main steam safety valve (MSSV), and residual heat release valve (RHRV) discharge pipes is not required above the main steam valve area roof, elevation 790 feet 6 inches. Per Section 10.3.5.2.2, a single steam generator is sufficient to maintain a minimum heat sink. Furthermore, only the MSSVs are required to maintain the plant in the safe shutdown hot standby condition as stated sections 10.3.1.2 and 14.1.11.1. A design basis missile can impact one or more discharge pipes on the main steam valve area roof and potentially render the associated valves inoperable; however, sufficient venting capability will be available following the design basis missile strike.

A design basis missile impact from the East is limiting. A design basis missile impact from the East is conservatively assumed to render one train of valves (MSSVs and ADV associated with a single steam generator) and the RHRV incapable of discharging steam to the atmosphere. One of the remaining ADVs is assumed to fail to satisfy the single failure criterion. Following the design basis missile impact, the plant would successfully achieve and maintain safe shutdown using the MSSVs of the remaining two steam generators. Further cooldown would be achieved through the remaining ADV.

10.3.1.2 Description

Steam from each of the three steam generators is conducted in 32 inch OD x 0.9297 inch minimum wall thickness, carbon steel pipe through swing disk-type trip and nonreturn valves, located in an enclosure immediately outside the reactor containment, to a 36 inch OD manifold which is located in the turbine building. A 2 inch bypass valve is provided around each of the swing disk type trip valves. Connections for the turbine steam bypass, turbine steam sealing system, reheater supply and auxiliary steam supply are provided at the manifold. A steam flowmeter interconnected with a three-element feedwater control system is provided in the main steam line between each steam generator and its main steam isolation valve. From the 36 inch OD manifold, the steam passes to the turbine throttle/stop valves and governor control valves.

The nonreturn valves automatically prevent reverse flow of steam in the case of accidental pressure reduction in any steam generator or its piping. If a steam line breaks between a nonreturn valve and a steam generator, the affected steam generator continues to blowdown while the nonreturn valve in the line prevents significant blowdown from the other steam generators. This steam line break accident is discussed in Section 14. The main steam trip valves provide backup for the nonreturn valves to prevent blowdown from intact steam generators through a ruptured pipe between a nonreturn valve and another steam generator.

The swing disk-type trip valve in series with each main steam isolation valve contains a free swinging disk normally held up out of the main steam flow path. If a pipe ruptures (Section 14) downstream of the trip valve, a signal derived as indicated in Section 7 causes all three trip valves to trip closed, thus stopping the flow of steam through the pipe rupture. Maximum closing time for the trip valves is 5 seconds following receipt of an isolation signal. Since these are swing check valves, actual closure times are much faster than 5 seconds. All analysis performed on a steam inventory basis is done using a 5 second closure. The analysis for steam hammer forces from valve closure uses the actual closure time. Valve closure checks

the sudden and large release of energy in the form of main steam, thereby preventing rapid cooling of the reactor coolant system. Trip valve closure also ensures a supply of steam to the turbine drive for the turbine-driven steam generator auxiliary feedpump.

The 2 inch bypass valves provided around each trip valve are motor operated globe valves. These valves are normally closed during power operation. The valves are used during plant heat-up to assist in warming up the main steam piping and in opening the trip valves. Interlocks are provided to the bypass valves to allow only one bypass valve to be open at a time. The bypass valves also receive one train of a main steam isolation signal. No credit for automatic closure from a steam isolation signal is taken to close the bypass valves in the accident analysis.

The common instrument air (Section 9.8) supply to the trip valves can be isolated and vented in the auxiliary feed pump room or the main steam valve area to manually close the trip valves in the event of a fire.

Five ASME Code safety valves are located in each main steam line outside the reactor containment and upstream of the nonreturn and trip valves. These safety valves are sized to pass steam flow resulting from a complete loss of load without exceeding 110% of the steam generator secondary side design pressure of 1085 psig. This is considered the most extreme accident condition.

Excess steam generated by the sensible heat in the nuclear steam supply system (NSSS), immediately following loss of load, is bypassed directly to the turbine condenser (Section 10.3.6) by means of two turbine steam bypass lines, which provide a total bypass capacity of greater than 40 percent of full load steam flow. Each bypass line contains a bank of nine steam bypass control valves arranged in parallel. These valves are controlled by reactor coolant average temperature with provisions to control a portion of the valves with steam pressure. A potential hazard in the form of an uncontrolled station cooldown caused by a large single valve sticking open is prevented by the use of this group of 18 valves installed in parallel. A single valve can pass a maximum steam flow of 890,000 lb per hour which is within the capability of the reactor transient criteria. The 18 valves combined can pass a nominal steam flow of 9,314,000 lb per hour based on a steam generator outlet full load steam pressure of 790 psia. A potential hazard equivalent to nine steam bypass valves remaining open and causing uncontrolled unit cooldown is the break of the steam line supplying one bank of bypass valves. Such a condition would initiate action to trip the unit. This would be followed by a complete load rejection with shutoff of main steam flow.

All or several of the bypass valves are opened under the following conditions, provided a turbine condenser vacuum permissive interlock is satisfied:

1. On a large step load decrease, the turbine steam bypass system creates a load on the steam generators, thus providing a controlled disposal of generated steam. An error signal exceeding a set value of reactor coolant T_{avg} minus T_{ref} fully opens all valves. T_{ref} is a function of load and is set automatically. The turbine steam bypass valves close automatically as reactor coolant conditions approach their programmed setpoint for the new load.

2. On a turbine trip with reactor trip, the pressure in the steam generators rises. To prevent overpressure without main steam safety valve operation, the turbine steam bypass valves open discharging to the condenser for several minutes, providing time for the reactor control system (Section 7.3) to reduce the thermal output of the reactor without exceeding acceptable core and coolant conditions (Section 3).

3. After a normal orderly shutdown of the turbine-generator leading to unit cooldown, the turbine steam bypass valves are used to release steam generated by the sensible heat for several hours. Unit cooldown, programmed to minimize thermal transients and based on sensible heat release, is effected by a gradual manual closing of the bypass valves until the cooldown process is transferred to the residual heat removal system (Section 9.3). During startup, hot standby service or physics testing, the bypass valves are manually operated from the main control board.

All bypass valves are prevented from opening on loss of condenser vacuum, and excess steam pressure is relieved to the atmosphere through the atmospheric dump valves or the main steam safety valves. Interlocks are provided to reduce the probability of spurious opening of the bypass valves.

In the event that the condenser becomes unavailable during a turbine trip, excess steam generated as a result of reactor coolant system (RCS) sensible heat and core residual heat is discharged to the atmosphere through the main steam safety valves. Radioactivity released during this discharge is assumed to be negligible since little or no primary coolant leakage is anticipated. Should significant radioactivity exist, as a result of leakage in the steam generators, concentration would be continually controlled to acceptable levels by the steam generator blowdown system. Any release of radioactive steam that takes place will be monitored by high range detectors located at the discharge points. A remote manually-operated atmospheric dump valve is also provided on each main steam header upstream of the nonreturn valve outside the containment. These valves are individually positioned from the main control board. The three valves each have a total effective relieving capacity of 319,900 lb per hour at an inlet pressure of 1035 psig, when accounting for friction losses associated with upstream and downstream piping.

In addition, a residual heat release control valve is provided which, after approximately 0.5 hr, is capable of releasing the sensible and core residual heat to the atmosphere via the residual heat release header. This valve is manually positioned from the main control board by remote control. This one valve, which is mounted on the common residual heat release header, serves all three steam generators through connections on each main steam line upstream of the nonreturn valve and trip valve. In addition, the residual heat release control valve is used to release the steam generated during reactor physics testing and operator training. There is a check valve in each line connecting a main steam line to the common residual heat release header. These check valves ensure that steam may flow to the header, but prevent reverse flow of steam as may occur if a line breaks between a steam generator and main steam nonreturn valve. When servicing all three steam generators, the residual heat release control valve has an effective relieving capacity of 229,426 lb/hr at an inlet pressure of 1035 psig taking into account friction losses associated with upstream and downstream piping.

Upon actuation of the atmospheric dump valves or the residual heat release control valve, any radioactive contaminants in the steam generators are released to the environment. These radioactive contaminants are monitored by the sampling system connections on the blowdown lines (Section 9.6). A system for continuous monitoring of releases to the environment is described in Section 11.3.3.3.24. The operator can control secondary system radioactivity concentrations at acceptable levels by steam generator blowdown system operation, reduction in power level, and/or isolation of a ruptured steam generator.

Steam can be supplied from each main steam line upstream of the trip valve to the turbine drive for the turbine-driven steam generator auxiliary feedwater pump (Section 10.3.5). The piping is arranged so that any steam generator can supply the turbine drive for this pump.

Check valves are provided in the steam supply line from each steam generator to the turbine drive to ensure the availability of driving steam in the event of failure of a steam generator or a line break upstream of a main steam nonreturn valve. Two trip open valves in parallel are located in the inlet of the turbine drive. Steam pressure is available at the inlet of these valves at all times. Indications of all operating conditions are available in the main control room to enable the operator to adjust feedwater flow by throttling valves at the pump discharge. Additional description of steam generator auxiliary feedwater pump operation is contained in Section 10.3.5.

Steam leaving the high pressure turbine passes through four moisture separator-reheater units in parallel to the inlets of the main low pressure turbine cylinders. Each of the four steam lines between the reheater outlet and low pressure turbine inlet is provided with a reheat stop valve and a reheat intercept valve in series. These valves, operated by the turbine control system, function to prevent turbine overspeed. An ASME Code safety valve is installed on each moisture separator reheater to protect the separators and reheat system from overpressure. The safety valves are designed to pass the flow resulting from closure of the reheat stop and intercept valves with the main steam inlet valves wide open. These valves discharge to the condenser.

10.3.1.3 Performance Analysis

If a main steam line break occurs (Section 14.2.5), a 2 out of 3 channel low pressure signal from any main steam line causes the swing trip valves in all three main steam lines to trip closed. Maximum closing time for the trip valves is 5 seconds following receipt of an isolation signal. If the break occurs downstream of the trip valve, valve closure stops the flow of steam through the break, thus checking the sudden and large release of energy in the form of steam. This prevents rapid cooling of the Reactor Coolant System (RCS). Trip valve closure also ensures a supply of steam to the turbine drive of the turbine-driven steam generator auxiliary feedwater pump, as described in Section 10.3.5.

If a main steam line breaks between a trip valve and a steam generator, the affected steam generator continues to blowdown. The nonreturn valve in the broken line prevents blowdown from the other steam generators. This is the worst steam line break accident and is discussed in Section 14.2.5.

10.3.1.4 Tests and Inspections

During unit refueling shutdown, the tripping mechanisms for the swing trip valves in the main steam lines are tested for proper operation in accordance with the BVPS Technical Specifications. The nonreturn valves are also tested to verify that they are in operable condition.

Preoperational testing includes a hydrostatic line test and a clean flush plus complete checkout of instrumentation components.

The turbine steam bypass system and the steam dump valves are operated in conjunction with the turbine overspeed test (Section 10.3.3.4).

To meet the inservice inspection requirements, the lines will be provided with removable insulation to permit ultrasonic testing of the welds upstream of the isolation valves. These welds are prepared to suit this inspection.

10.3.2 Auxiliary Steam System

10.3.2.1 Design Bases

The auxiliary steam system piping is designed in accordance with the Code for Pressure Piping, ANSI B31.1.

The purpose of the auxiliary steam system (capable of supplying 86,000 lb per hr of saturated steam) is to distribute 150 psig steam throughout the station for auxiliary services, including the following:

1. Turbine gland steam during startup, normal operation and shutdown
2. Condenser steam jet air ejectors
3. Condenser vacuum priming ejectors
4. Building heating and other building services
5. Outdoor tank heating
6. Containment vacuum ejector.

10.3.2.2 Description

The auxiliary steam system is supplied from the main steam header through a pressure reducing valve. When this steam is not available, such as during station shutdown, steam is supplied to the auxiliary steam system from BVPS-2. A condensate receiver and condensate pumps are used to collect condensate and return it to BVPS-2 for reuse as necessary when the steam source is BVPS-2. Upon unexpected loss of auxiliary steam, the capability exists to supply auxiliary steam from the gland steam system, via the main steam system.

There is a capability to supply steam from the auxiliary header to the turbine gland steam system during startup and low load operation.

The containment vacuum ejector (Section 5.4.2) is used only during startup periods to initially evacuate the containment. During normal operation, two mechanical vacuum pumps maintain the vacuum as described in Section 5.4.2.

Condenser vacuum priming ejectors are used during startup to draw the initial condenser vacuum. During normal operation the steam jet air ejectors maintain condenser vacuum as described in Section 10.3.6.

10.3.2.3 Safety Analysis

No services supplied by the auxiliary steam system perform a safety-related function.

10.3.2.4 Tests and Inspections

During the normal life of the station, the auxiliary steam system is in continuous operation and performance tests are not required. Visual inspections are conducted following installation of spare parts or piping modifications, to confirm normal operation of the system.

10.3.3 Turbine-Generator

The turbine-generator heat balance representing the Nuclear Steam Supply System output rating of 2,910 MWt is shown in Figure 10.2-1.

10.3.3.1 Design Bases

The turbine-generator is a conventional 1,800 rpm tandem compound unit, consisting of one double flow high pressure cylinder and two double flow low pressure cylinders.

A gland steam sealing system is provided to prevent air inleakage and steam outleakage along the turbine shaft. A gland steam pressure regulator, gland steam condenser and all necessary piping and control are provided. In addition, the gland steam sealing system provides a backup source of steam for the auxiliary steam system header during normal plant operation.

The high and low pressure turbine gland seals are served by the gland steam system. The source of steam may be either main steam or auxiliary steam. A motor-operated bypass valve can be opened to furnish steam to the seals should the main pressure regulator fail.

The noncondensable gases in the gland steam are exhausted to the environment. Radioactivity will present no hazard due to the small percentage of steam required for this system, and the controls provided by the steam generator blowdown system (Section 10.3.8) for maintaining acceptable levels of radioactivity.

The hydrogen cooled generator is rated at 1070 MVA at 75 psig hydrogen pressure, 0.92 power factor, 0.62 short circuit ratio, 3 phase, 60 Hz, 22 KV, 1,800 rpm. Generator rating, temperature rise and insulation class are all in accordance with the applicable ANSI Standards.

10.3.3.2 Description

The 36 inch OD steam manifold is connected to the turbine through four steam lines, each of which has a turbine throttle stop valve. The main steam is supplied through governor control valves to the high pressure cylinder. Steam passes from the high pressure cylinder to the moisture separator reheaters. There are four moisture separator reheaters, one on each side of the two low pressure turbines. A stop valve and an intercept valve are provided at the discharge of each moisture separator reheater before steam enters the two low pressure turbines. High pressure steam from the main steam header is provided for the heating steam in the moisture separator reheaters.

Steam passes from the two low pressure turbines to the condenser. Six stages of extraction steam are provided for feedwater heating.

A complete steam sealing system is provided, including automatic air-operated valves, interconnecting piping and controls to maintain constant 3 psig pressure at the turbine seals under all operating conditions. Steam leakage at the high and low pressure turbine glands is carried away and condensed by a gland steam condenser. The noncondensable gases are removed from the gland steam condenser by one of two motor-driven exhausters and discharged to the atmosphere.

The turbine oil systems include an electrohydraulically controlled governing-trip system and a low pressure bearing lubrication system as discussed in Section 10.3.7. The electrohydraulic governor system includes a solid state electronic governor controller with several actuators in the high pressure hydraulic fluid system for positioning turbine throttle, governor control, and reheat stop and intercept valves.

The hydrogen seal oil system is provided to prevent the escape of generator hydrogen. Hydrogen side and air side a-c motor-driven pumps supply oil to the dual seals at each end of the generator. Seal oil drains from the generator seals then passes through a detraining section for hydrogen removal before returning to the hydrogen side seal oil receiver or the turbine oil tank. A DC motor-driven air side seal oil pump prevents the escape of hydrogen during a loss of offsite power.

A complete hydrogen control system is provided including cabinet, interconnecting piping, alarms and controls to maintain the correct hydrogen pressure and purity in the generator under all operating conditions. Hydrogen is supplied to the control cabinet from an outdoor bulk storage facility. Inert carbon dioxide gas is supplied from a refrigerated bulk storage unit to purge the generator of either hydrogen or air.

A rotating rectifier brushless exciter with a response ratio of 0.5 is provided. The exciter is rated at 3,300 kW, 500 V DC, 1,800 rpm. The exciter consists of an AC alternator coupled directly to the generator rotor. The alternator field winding is stationary and control of the exciter is applied to this winding. The alternator armature is rectified by banks of diodes that rotate with the armature. This d-c output is carried through a hollow section of the shaft and is applied directly to the main generator field.

The 22 KV generator terminals are connected to the main step-up transformer and two unit station service transformers by means of a 22 KV aluminum conductor and enclosed isolated phase bus duct. This bus duct is rated at 29,600 amp and is forced air-cooled.

10.3.3.3 Performance Analysis

Primary protection of the main generator is provided by differential current and field failure relays. Protective relays automatically trip the turbine throttle stop valves and electrically isolate the generator.

Turbine trips are provided for protection of the turbine-generator and safety of personnel and surrounding equipment. The turbine trip is accomplished by shutting off all steam flow to and through the turbine by simultaneously closing all throttle stop valves, governor control valves, intercept valves and reheater stop valves. Turbine trips are provided for low bearing oil pressure, thrust bearing failure, low condenser vacuum, overspeed and all generator trips. The turbine can be tripped manually. Reactor trips and steam generator high high level can also trip the turbine.

This system has been reviewed on the basis of a full load trip of the turbine generator along with loss of normal power. During such an event, there would be no serious effect on the reactor. For interaction of the turbine controls and reactor controls, see description in Sections 7.2 and 7.3, supported by Figure 7.2-1.

For a discussion of turbine overspeed, see Section 14.1.12.

10.3.3.4 Tests and Inspections

The main turbine throttle and governor valves and the combined intercept and intermediate stop valves are exercised in accordance with the requirements contained in the Licensing Requirements Manual to detect possible valve stem sticking. The valves are closed and then reopened during this procedure. The turbine is overspeed checked at a refueling frequency. (This test may be performed at the beginning of an outage rather than at startup, providing no work will be performed during the outage that could affect the overspeed trip setpoint.) This is done by running the turbine up to the overspeed trip points. A device is also included with the turbine for testing the overspeed trip mechanism without actually overspeeding the turbine.

10.3.3.5 In-Service Inspection

The inservice inspection of the steam turbine assembly will be conducted to provide assurance against brittle failure of a disc at rated speed or design and intermediate overspeed. The inservice inspection will be performed when required to maintain the probability of turbine missile generation (P1) less than or equal to 10^{-5}, as described in Section 14.1.12.4. The inspection interval is based upon the probability of generating a turbine missile as a function of actual operating time.

When the turbine is disassembled, a visual and magnetic particle examination is made externally on accessible areas of the high pressure rotor, low pressure turbine blades, and low pressure discs. The coupling and coupling bolts are visually examined.

Inspection Techniques

Two ultrasonic inspection techniques may be employed for detecting cracks in keyways and bores without need for unshrinking discs. One technique, called the tangential aim technique, detects indications because of its high sensitivity and the other, called the radial aim technique, verifies indications and measures their depths.

Tangential Aim Technique

In the tangential aim technique, an ultrasonic transducer is mounted on a plexiglas block that sits on the disc hub. The plexiglas block is contoured so that it is in complete contact with the disc hub. The ultrasonic waves are directed tangentially towards the bore/keyway so that any cracks above the bore/keyway area will be perpendicular to the sound beam and reflect the sound. A careful analysis of the time differences between the echos from the keyway and cracks should allow discrimination of false indications.

Radial Aim Technique

Because stress corrosion cracks have been found to be branched, the radial aim technique has been successfully used to verify the presence and quantify the depth of cracks. In this technique, the ultrasonic waves are directed perpendicular to the keyway/bore. The depth of the crack is estimated from the time difference between an echo from the crack and the echo from the keyway crown or bore.

10.3.4 Circulating Water System

The circulating water system (Figure 10.3-3) provides cooling water for the main surface condenser (Section 10.3.6) of the turbine generator unit. It is a closed loop system consisting of a cooling tower, piping to and from the condenser, a pumping structure and pumps. Makeup water is supplied to the closed loop circulating water system by discharging the turbine plant raw water system and the reactor plant river water system into the circulating water condenser discharge lines.

10.3.4.1 Design Bases

The circulating water system is designed to dissipate all rejected heat from the turbine cycle to the atmosphere, by means of a cooling tower. The four cooling tower pumps are designed to pump the total circulating water flow plus the raw water and river water discharge flow to the top of the cooling tower fill.

The cooling tower design parameters are listed in Table 10.3-1. Cooling tower pump design parameters are listed in Table 10.3-2.

Circulating water piping is mainly made up of concrete pipe. The bifurcations and special shapes are fabricated steel plate pipe encased in concrete.

10.3.4.2 Description

Circulating water flows by gravity from the basin of the cooling tower, through screens, through two 108 inch diameter circulating water pipes to the inlet water boxes of the condenser. The water passes through the tubes of the condenser to the outlet water boxes. Two 108 inch lines carry condenser discharge cooling water to a pumping structure outside of the turbine building. The discharge lines of the raw water system and the river water system flow into the circulating water system between the condenser outlet water boxes and the pumping structure. The four cooling tower pumps are mounted in the pumping structure. These cooling tower pumps pump the water to the top of the cooling tower fill where it is discharged into the cooling tower distribution system. Cooling tower blowdown passes from an overflow at the cooling tower basin and is discharged back into the Ohio River.

A minimum cooling tower blowdown rate of 9,000 gpm is anticipated during normal unit operation. However, this blowdown rate can be raised to 22,500 gpm if dilution of radioactive liquid waste discharge is found necessary to meet the guidelines of 10CFR50, Appendix I (see Appendix 11A).

The circulating water system is a nonsafety related system and is independent of emergency core cooling requirements.

The worst possible postulated break in the circulating water system is the rupture of the main condenser inlet expansion joint with failure of its associated condenser inlet valve to close. This break would allow the largest quantity of water to flow from the cooling tower basin to the turbine building basement with no means available to stop the flow.

The normal capacity of the cooling water tower basin is approximately 5,945,000 gal. The flow rate through the ruptured expansion joint, assuming a double ended break configuration, is approximately 120,000 gpm. The capacity of the turbine building basement is 270,000 gal per ft. Therefore, the water level would rise on the order of 0.45 ft per minute.

When the level equalization point is reached between the final water level in the turbine building and the tower basin, and the flow has ceased, the water level in the turbine building will have risen 9.3 ft while the level in the basin will have fallen 2.2 ft; both surfaces will be approximately at El. 702.8 ft.

There are no possible paths for water to flow from the turbine building at or below El. 707.5 ft. All possible paths of floodwaters leaving the turbine building and flowing to other areas during a PMF, which produces a water level far greater than the level which could be obtained by a circulating water system failure, are discussed in Sections 2.3.3, 2.7.3.2.3 and 9.7.

Operation of the condenser inlet valves would, of course, limit the quantity to something less than 120,000 gal (60 second valve closure time).

Design parameters of the circulating water system components are listed in Table 10.3-3.

The cooling tower is located at a distance such that its failure would not cause disruption of safety-related systems.

The cooling tower pumps are not designed to, nor are they required to, meet single failure criteria.

10.3.4.3 Performance Analysis

All four cooling tower pumps are normally in service. If a cooling tower pump is out of service, operation of the turbine-generator can be continued, but the station output may have to be reduced.

The turbine-generator plant cannot operate should the cooling tower be out of service for any reason.

Motor operated valves installed at the condenser inlet and outlet permit isolation of each half of each condenser shell for in-service maintenance.

10.3.4.4 Tests and Inspections

Automatic operation of the cooling tower pump discharge valve is checked during initial operation and operationally thereafter.

10.3.5 Condensate and Feedwater Systems

The condensate and feedwater systems are shown in Figure 10.3-4 and 10.3-5, respectively. The heat balance applicable for operation at licensed power conditions is shown in Figure 10.2-1.

10.3.5.1 Design Bases

10.3.5.1.1 Condensate and Feedwater Systems

The condensate and feedwater system design is based on removing condensate from the hotwell of the condenser and supplying heated feedwater to the steam generators at all load conditions.

The feedwater system between the steam generators and the containment isolation valves outside the containment is required during shutdown of the unit and is thus designed as Seismic Category I (Updated FSAR Appendix B) and in accordance with the Code for Pressure Piping, ANSI B31.1. All piping within the containment is adequately protected from missiles, pipe whip and environmental conditions.

The main feedwater system performs the following three safety-related functions:

1. Automatically isolate main feedwater flow to the steam generators following a feedwater isolation signal (Section 7.3).

2. The Piping Class II (Q2) piping of the main feedwater system provides a barrier against release of containment atmosphere during a loss-of-coolant accident (LOCA). This barrier, which is part of the containment, serves the same function as the containment liner.

3. The Piping Class II (Q2) piping from the steam generators to and including the check valves just outside the containment, is required for the auxiliary feedwater system (AFWS) to maintain the steam generator levels when the main feedwater pumps are not available.

The condensate system is located totally within the turbine building. Aside from causing a plant shutdown, a condensate line rupture or failure of a structure housing portions of the condensate system cannot compromise the availability of any safety-related equipment.

10.3.5.1.2 Auxiliary Feedwater Systems (AFWS)

The design of the steam generator auxiliary feedwater subsystem portion of the feedwater system is based on the following conditions:

1. Integrated residual heat release from a full power equilibrium core

2. Feedwater inventory of the steam generators operating at normal minimum feedwater level

3. The minimum allowable steam generator feedwater level permitted to prevent thermal shock or other damage

4. A reasonable time interval to start the steam generator auxiliary feedwater pumps

5. The temperature of the feedwater supplied from the primary plant demineralized water storage tank. This temperature is assumed to be 35°F when considering thermal shock and 100°F when considering feedwater enthalpy for tank sizing.

The entire auxiliary feedwater subsystem is designed as Seismic Category I, with the exception of the primary demineralized water chemical feed tank.

No portion of the auxiliary feedwater system (AFWS) is within the containment. The system, with the exception of the primary plant demineralized water storage tank and pump suction piping, is located in the auxiliary feedwater pump cubicle and main steam and valve cubicle. The auxiliary feedwater system outside containment is housed in a missile protected area.

Cavitating venturi flow orifices are provided in the auxiliary feedwater supply lines to each of the three steam generators. These venturi orifices are designed to limit the flow to 310 gpm (choked flow) to any steam generator. In the event of a steamline break that will result in a decrease in the steam generator shell pressure, the venturis will prevent excessive flow to the depressurized steam generator to prevent Containment over-pressurization.

The system is designed such that for any accident requiring the use of the AFWS, a single active (electrical) failure in the AFWS will not preclude the system's ability to perform its function. The positions of these valves are indicated in the control room. The instrumentation, control and electrical equipment of this system conforms to the requirements of Institute for Electrical and Electronic Engineers (IEEE) 279-1971 Criteria for Protection Systems for Nuclear Power Generating Stations and IEEE 308-1971 Criteria for Class 1E Power Systems for Nuclear Power Generating Stations.

10.3.5.2 Description

10.3.5.2.1 Condensate and Feedwater Systems

Condensate is withdrawn from the condenser hotwells by two half-size capacity motor-driven condensate pumps. The pumps discharge into a common header which carries the condensate through two steam jet air ejector condensers arranged in parallel and through one gland steam condenser. A flow control valve and a bypass around the gland steam condenser ensure that no more than maximum design flow passes through the gland steam condenser. Downstream of the gland steam condenser, the common header divides into two lines which carry the condensate through the tube side of two trains of heat exchangers arranged in parallel, each consisting of one heater drain cooler and five low pressure feedwater headers (No. 2 through 6), each half-capacity. The effluent from each train combines into a common suction header for the two half-size design capacity steam generator feedwater pumps. Manual valves permit isolation of one train of heaters for maintenance without a station shutdown.

The condenser hotwell is designed to operate at normal level such that approximately 4 minutes of condensate flow (71,000 gal) is available to supply the condensate pumps. A 200,000 gal turbine plant demineralized water storage tank floats on the system. Each of the two vertical barrel-type condensate pumps is rated at 9,700 gpm at 1,078 ft TDH. Minimum flow of approximately 3,000 gpm total for each of the two condensate pumps is maintained by an orifice measuring device. The orifice measuring device operates the recirculation valve downstream of the gland steam condenser as shown in Figure 10.3-4.

Two half-size steam generator feedwater pumps, each rated at 15,200 gpm and 1,700 ft TDH, are furnished to supply feedwater to the three steam generators. Each feedwater pump is equipped with two 4,000 hp electric motor drivers in tandem. Minimum flow for each pump is maintained by administrative control and an automatic recirculation control and alarm system, consisting of: flow measuring nozzles, flow totalizer, controller, and recirculation valves. The recirculation valves normally maintain a minimum flow of 8,000 gpm per pump. Feedwater leaves the first-point heaters at 440°F.

The steam generator feedwater pumps discharge through two half-size design capacity high pressure feedwater heaters (No. 1), arranged in parallel, to a common discharge header for distribution to the steam generators through individual feedwater flow control valves, positioned by the three-element feedwater control system for each steam generator. A manual bypass around each first-point heater allows isolation of these heaters for maintenance without a station shutdown. During low power operation or hot shutdown, when feedwater flow is below 20 percent of design flow, a bypass valve around each feedwater control valve provides steam generator level and feedwater flow control. The automatic control of the steam generator water level at low power using the feedwater bypass valve is also discussed in Section 7.7.1.7.

The feedwater control valves and bypass valves are provided with indicating lights in the main control room. The feedwater control valves close on receipt of a safety injection (SI) signal or any steam generator two out of three high-high level or a reactor trip associated with a low T_{avg} in two out of three reactor loops. The feedwater bypass control valves close on a feedwater isolation signal made up of an SI signal or any steam generator two out of three high-high level. The feedwater bypass valves must be reset by a pushbutton switch located in the main control room after the isolation signal is removed.

Control switches with indicating lights are provided in the main control room for the feedwater isolation valves. A set of indicating lights is also provided on the feedwater isolation valve local panel. These feedwater isolation valves isolate each steam generator upon receiving a feedwater isolation signal, which is made up of an SI signal or any steam generator two out of three high-high level. These valves will be reset by the SI reset pushbutton switch in the main control room after the isolation signal is removed.

An automatic bypass is used to bypass all the low pressure heaters between the condensate pump discharge and the steam generator feedpump suction in the event of a sudden load reduction. This enables the condensate pumps to supply adequate suction to the steam generator feedpumps.

Drains from the moisture separator reheater units and the No. 1 and No. 2 feedwater heaters are collected in the heater drain tank and pumped into the suction of the steam generator feedpumps by one of the two full-capacity heater drain pumps. Drains from heater No. 3 cascade to heater No. 4 and from heater No. 4 to heater No. 5 and from heater No. 5 through the drain cooler to the condenser. Drains from heater No. 6 flow directly to the condenser. An alternate drain line is provided directly to the condenser from the heater drain tank and feedwater heaters Nos. 1, 3, 4, 5 and 6.

Condensate from the condenser hotwell may be discharged under administrative control through either a double valved connection line to the circulating water line, if activity levels permit, or through a normally closed connection to the liquid waste disposal system (Section 11.2.4). The condensers may also be emptied by pumping, with the condensate pumps, into the turbine plant demineralized water storage tank. This tank also supplies makeup to the condenser hotwells. During normal operation, discharge of condensate to the tank and makeup from the tank are automatically controlled by the hotwell level.

Chemical feed equipment is used to add chemical solutions to the discharge of the condensate pumps in the condensate and feedwater systems. The chemicals control residual oxygen content, maintain pH at levels specified in the BVPS-1 Chemistry Manual and inhibit corrosion so as to reduce pickup of metal by the feedwater.

Solutions are mixed and stored in chemical feedtanks. The solutions are pumped into the main condensate system by motor-driven positive displacement pumps with manually adjustable stroke.

10.3.5.2.2 Auxiliary Feedwater System

The steam generator auxiliary feedwater pumps are used as an emergency source of feedwater supply to the steam generators. They are required to ensure safe shutdown in the event of a main turbine trip with complete loss of normal electric power to the station. They are also started on a safety injection signal (Section 7). Except for periodic start-ups to check serviceability and use during normal station start-up to fill the steam generators, these pumps are on standby service only.

A turbine-driven steam generator auxiliary feedwater pump rated at 700 gpm and 2,696 ft TDH, and two motor-driven steam generator auxiliary feedwater pumps each rated at 350 gpm and 2,696 ft TDH are furnished. The turbine drive can be supplied with steam from each steam generator outlet header. The electric motors receive power from the emergency diesel generators when normal station power is lost.

The steam generator auxiliary feedwater pumps normally take suction from the primary plant demineralized water storage tank which has a minimum usable volume of 130,000 gallons. The pumps can also be supplied with water by the river water pumps (Section 9.9) or the engine-driven fire pump via one of the river water system headers.

The steam generator auxiliary feedwater pumps can be started either manually or automatically from the main control board. In addition, the pumps can be manually started from the shutdown control panel (Section 7.7).

Feedwater from the steam generator auxiliary feedpumps is pumped to each steam generator through normally open control valves. Flow is monitored in each line by flow indicators. Each control valve may be adjusted from the main control board as dictated by the steam generator water level and auxiliary feedwater flow rate. These valves can also be adjusted from the shutdown control panel. In the event of a loss of power, these valves are equipped with handwheels and can be adjusted by hand.

Cavitating venturi flow orifices are provided in the auxiliary feedwater supply lines to each of the three steam generators. The cavitating venturis are fabricated to ASME III, Class 3 requirements with a design pressure of 1500 psig and design temperature of 120°F. The connecting piping and support modifications are designed in accordance with the BV Unit 1 safety class III (Q3), piping code B31.1, and seismic category criteria.

The steam generators are a source of steam for the turbine drive of the turbine-driven steam generator auxiliary feedwater pump. During the initial phase of reactor cooldown, the steam generators deliver approximately 1,100 psia of saturated steam. As the reactor cools, the steam pressure drops and the turbine drive speed slows. When the turbine drive speed slows sufficiently, the pump is shut down and the residual heat removal system is placed in service. The two electric motor-driven pumps are controlled to perform in a similar manner. A second set of auxiliary feedwater lines with three normally open control valves parallels the primary lines for increased reliability.

During operation, each pump continuously recirculates a specified flow back to the demineralized water storage tank through a common header. Cooling water for auxiliary feedwater pump bearing oil coolers is supplied from this continuous recirculation flow. This provides a guaranteed source of coolant under all conditions. The pumps are sized to supply their rated capacities plus this recirculation. Each pump is equipped with a recirculating line for long-term pump operation. The turbine driven pump is equipped with a 3 inch line to provide 250 gpm recirculating flow minimum and each motor driven pump with a 2 inch line to provide a minimum recirculating flow of 135 gpm. Each of the recirculating lines is equipped with an automatically operated valve.

The recirculation header is also provided with a chemical feed tank for introducing chemicals to protect the carbon steel pumps, piping and primary plant demineralized water storage tank from the deleterious effects of dissolved oxygen in demineralized water.

The auxiliary feedwater is discharged to the steam generators through a connection in each main feedwater line outside the reactor containment but downstream of the containment isolation trip and check valve. This prevents loss of the auxiliary feedwater should a feedwater line break upstream of this check valve.

The system provides sufficient redundancy to ensure the required flow to a minimum of two steam generators while subjected to a single failure as defined in Section 1.3.1. To maintain a minimum heat sink, water must be supplied to a minimum of one steam generator.

When the motor driven auxiliary feedwater pump aligned to the redundant header is declared inoperable, the two remaining auxiliary feedwater pumps will be realigned to separate headers as per Technical Specifications. This action will maintain the necessary configuration to assure adequate auxiliary feedwater flow for normal, transient and accident conditions.

10.3.5.2.3 Dedicated Auxiliary Feedwater System

This motor driven dedicated auxiliary feedwater pump, FW-P-4, is designed to provide water to the three steam generators after the loss of main feedwater and the existing auxiliary feedwater pumps, due to the loss of offsite power and a fire in the auxiliary feedwater pump area or associated control or power circuitry. It is powered from the emergency response facility substation, switchgear diesel, and is located on the 693'-6" elevation of the turbine building.

Control and power cables for this pump and substation power supply is routed in the turbine building alone independent of control room and other fire areas.

Suction to FW-P-4 is normally aligned to WT-TK-11 (turbine plant demineralized water). Additional makeup water is provided from alignment to WT-TK-26.

The capacity of these storage tanks will ensure that the dedicated auxiliary feedwater pump will be able to initiate a plant cooldown and meet the makeup capacity requirements necessary to remove the plant decay heat generated during the first 72 hours of a shutdown. Makeup water may be provided by trucking in water from an outside source or by using the river water system.

The pump is designed to deliver 400 gpm at the time of initiation to 700 gpm at the reduced steam generator pressures in the approach to the 200°F cold shutdown state. This dedicated pump has the capability to utilize the steam generators as once through water to water heat exchangers, with the design intent of reaching cold shutdown conditions in 127 hours.

10.3.5.3 Design Evaluation

Steam supply lines to the trip valves of the turbine-driven steam generator auxiliary feedwater pump are continuously under main steam pressure. Steam traps are provided in the lines to ensure that any condensate formed as a result of warming is removed. The turbine is a single inlet, single stage unit and any drops of water forming do not damage or impair its operation. When main steam pressure is no longer adequate to operate the turbine-driven pump, the need for residual heat removal is reduced to a level where the residual heat removal system (Section 9.3) can be used. In addition, each motor-driven pump is connected to an emergency bus and can be operated if necessary. An alternate source for auxiliary feedwater is one of the river water system headers, which is connected to the suction of the steam generator auxiliary feedwater pumps and can be supplied with water by either the river water pumps or the engine-driven fire pump.

Cavitating venturis provided in the three auxiliary feedwater supply lines reduce the minimum auxiliary feedwater flow available to the steam generators and limit the maximum auxiliary feedwater flow to a faulted steam generator or broken feedwater line. Minimum auxiliary feedwater pump performance with the cavitating venturis meets the flow requirements assumed in the Feedwater Line Break, Loss of Normal Feedwater and Small Break LOCA analyses.

The three steam generator auxiliary feedwater pumps with the redundant means of motive power and associated piping (with the exception of the TDAFWP steam exhaust stacks above elevation 790 feet) are installed in a tornado-protected area adjacent to the containment so that their use can be relied upon during any loss of normal station power.

10.3.5.4 Test and Inspections

The steam generator auxiliary feedwater pumps, their drives and the pump discharge valves are tested on a periodic basis. Steam is admitted to the turbine drive or the motor drivers are energized and flow is established by recirculation to the primary plant demineralized water storage tank. During station startups after extended shutdown the motor operated shutoff valves leading to the main feedwater lines are opened, and flow indication is observed at the main control board for each loop. All weld surfaces are properly prepared to permit volumetric inspection and removable insulation is provided for feedwater and auxiliary feedwater lines from the steam generator to the first isolation valve outside containment.

10.3.6 Condenser

A twin shell, single pass, divided water box condenser is provided for condensing steam from the two low pressure turbine exhausts, from the turbine steam bypass valves and for miscellaneous drains.

10.3.6.1 Design Bases

The design parameters for the condenser are as given in Table 10.3-4.

10.3.6.2 Description

The condenser is of conventional design, that has the following features: stainless steel expansion joint in each neck, steam and condensate crossover ducts to equalize pressure, impingement baffles to protect the tubes and partitioned hotwells for detection of circulating water inleakage. The total storage capacity of both condenser hotwells, based on normal level, is equivalent to approximately 4 minutes of full load operation. One No. 6 feedwater heater shell is located in each condenser neck.

Two twin element, two-stage steam jet air ejector units, each complete with tubed inner and after condensers, remove noncondensable gases from the condenser shells. One element of each ejector is operated for each condenser shell. The ejectors utilize auxiliary steam for operation. The air ejector effluent is monitored for radiation as discussed in Section 10.3.8.

For initial condenser shell side air removal, a vacuum priming ejector is provided for each shell. Steam from the auxiliary steam system operates these ejectors (Section 10.3.2).

10.3.6.3 Design Evaluation

The condenser is designed for operation at maximum expected station capability. Tubes in the condenser are protected by impingement baffles and spray pipes. Motor-operated butterfly valves are provided at the condenser inlet and outlet water boxes for maintenance isolation. Any radioactive contaminants will be handled by the air ejectors as described in Section 10.3.8.2.

Normally, air leakage to the condenser will be handled by the steam air ejectors. Should air leakage become excessive so that backpressure cannot be maintained, the unit will trip. Unless a break occurs, the leakage should be nominal and controllable to permit repairs during a planned shutdown.

10.3.6.4 Tests and Inspections

A total of 12 sample points on the condenser hotwells are used to check the condenser for circulating water inleakage. A radiation monitor is installed in the common discharge line of the two air ejectors.

10.3.7 <u>Lubricating Oil System</u>

The lubricating oil system provides for storage, transfer and conditioning of lubricating oil for the turbine-generator.

10.3.7.1 Design Bases

The lubricating oil system performs the following functions:

1. Stores lubricating oil

2. Supplies oil to and receives oil from the turbine-generator oil reservoir at 100 gpm

3. Purifies oil, at a rate of up to approximately 100 gpm, from the turbine-generator oil reservoir on a continuous offstream basis.

10.3.7.2 Description

A 14,500 gal capacity oil storage tank and two transfer pumps are located at basement grade in the turbine building. Two connections are located outside the turbine building to allow for receiving fresh oil from or discharging used oil into tank trucks. The piping associated with one transfer pump is arranged to deliver oil to the turbine oil reservoir or into tank trucks from the oil storage tank. The second transfer pump can deliver turbine oil into tank trucks from the turbine oil reservoir or return it to the oil storage tank. All piping is welded steel.

Oil is continuously extracted from an overflow fitting on the turbine oil reservoir and pumped through a lubricating oil purifier which removes entrained water and impurities from the oil. After passing through this lubricating oil purifier, the oil is returned to the turbine oil reservoir.

A vapor extractor removes combustible gases from the turbine oil reservoir. It vents these gases to the atmosphere outside the turbine building.

A shaft-driven oil pump supplies all lubricating oil to the turbine-generator when the turbine is at operating speed. AC motor-driven bearing oil pumps supply lubricating oil during startup, shutdown and standby conditions. An emergency DC motor-driven bearing oil pump operated from the station battery ensures lubricating oil to the turbine-generator when the AC motor-driven pump is not available. An AC turning gear oil pump supplies bearing oil for operating the unit on turning gear.

The turbine plant cooling water system (Section 10.3.9) supplies cooling water to the turbine lube oil coolers which are located adjacent to the turbine oil reservoir.

10.3.7.3 Design Evaluation

The DC bearing oil pump is required to operate in the event of loss-of-station power. This pump protects the turbine during coastdown. The station battery provides an uninterrupted source of power to this pump. No other part of the lubricating oil system is required to operate during loss-of-station power.

10.3.7.4 Tests and Inspections

The d-c bearing oil pump is tested periodically by running it during normal operation.

10.3.8 Secondary Vent and Drain System

Vents and drains are arranged in much the same manner as those in a fossil fuel power station, since the steam and power conversion system is normally nonradioactive. Air ejector vents and steam generator blowdown are continuously monitored and the air ejector vents are discharged under controlled conditions, because of possible radioactive contamination.

The steam generator blowdown subsystem is shown in Figure 10.3-6.

10.3.8.1 Design Bases

Each condenser steam jet air ejector is designed to remove 20 scfm of free air. Each ejector normally uses 1,200 lb per hr of saturated steam at 125 psig from the auxiliary steam header, while using 9,700 gpm of condensate for cooling. Separate hogging or vacuum priming jets are used to establish condenser vacuum during startup.

The three steam generators are expected to collectively blow down a maximum of 400 gpm of liquid to the blowdown tank, FW-TK-3, with two steam generator transfer pumps and two blowdown demineralizers in service. This demineralizer system is provided for control of secondary side water chemistry and to assist in minimizing the buildup of ionic impurities and corrosion products in the steam generators.

10.3.8.2 Description

Noncondensable gases which are removed from the condenser by the air ejectors are normally discharged to the gaseous waste disposal system (Section 11.2.3) upstream of the gaseous waste disposal filters for processing and discharge via the process vent at the top of the Unit 1 cooling tower.

In the event of a steam generator tube leak, with subsequent contamination of the steam, radioactive noncondensable gases separate from the steam and concentrate in the main condenser. The main condenser air ejectors remove noncondensable gases from the condenser. The principle radio-isotopes extracted from the condenser during design leakage conditions are Xe133 and Kr85.

In the event the high-high radioactivity level is reached by radiation monitor (RM-SV-100) downstream of the air ejectors, trip valves in the air ejector effluent line automatically divert the effluent flow to the containment for immediate termination of direct environmental release. Condensed liquid in the air ejectors drains into the steam jet air ejector tank. This liquid can be pumped to the steam generator blowdown system or drained back to the condenser.

Other systems handling carbon dioxide, hydrogen and oil vapor and other nonradioactive gases are vented directly to the atmosphere outside the building.

During startup, the priming air ejectors are operated to obtain a vacuum on the condenser. The vapors removed are discharged to the atmosphere. Contaminants contained in the steam-air mixture will not create a hazard to the environment. Radioactivity due to primary-to-secondary leakage is continually monitored so as to control it within acceptable limits.

Each steam generator is provided with blowdown connections for shell solids concentration control. The rate of blowdown from each steam generator is controlled by a manually-operated needle-type flow control valve.

Normally blowdown from each steam generator flows to steam generator blowdown tank FW-TK-3. Twenty-five to thirty percent of this blowdown flashes to steam in FW-TK-3. The flashed steam is directed to the third point extraction feedwater heaters, FW-E-3A and -3B, when the plant is operating at greater than 60 percent power or to the main condenser when the plant is operating at less than 60 percent power. The remaining liquid is pumped by two steam generator transfer pumps, BD-P-1A and -1B, through a heat exchanger, FW-E-9, and a filter, BD-FL-1, to the blowdown demineralizers, BD-I-1A and -1B.

For normal operation, one 100 percent capacity steam generator transfer pump is in service; the other 100 percent capacity pump is in standby.

When in service, the filter BD-FL-1, is periodically backwashed using the backwash receiver tank, BD-TK-1, a pneumatic booster system, BD-TK-2, and a backwash transfer pump, BD-P-2. The contents of backwash receiver tank, BD-TK-1, are recirculated to provide mixing and sampling prior to discharge to the liquid waste disposal system (Figure 11.2-3) and disposal in the cooling tower blowdown lines.

After the water is cooled, it is directed to the mixed bed demineralizers, BD-I-1A or -1B. For normal operation, one demineralizer will be in service with the other in standby. The water from these demineralizers is directed through one of the two blowdown strainers (BD-ST-1A and -1B) to the main condenser.

The resin transfer system is used to transfer spent resin from demineralizers BD-I-1A or -1B to the spent resin hold tank, BD-TK-4. Spent resin may be regenerated onsite or transferred to drums or a tank truck prior to shipping offsite.

The cooled blowdown water from heat exchanger, FW-E-9, can be directed to the main condenser instead of demineralizers, BD-I-1A or -1B.

To minimize the potential for radioactive contamination of the above blowdown equipment, an offline radiation monitor, RM-BD-101, continuously samples the blowdown from a point downstream of blowdown heat exchanger, FW-E-9. Radiation monitor RM-BD-101 alerts the plant operators of a potential steam generator tube leak.

Operator action may divert blowdown from the faulted steam generator to the steam generator blowdown tank, FW-TK-1. A temporary disposable demineralizer may be installed to treat radioactively contaminated blowdown. Contaminated blowdown may be directed to the steam generator blowdown holding tank LW-TK-7A and -7B or to the condenser through a temporary demineralizer. The steam generator blowdown holding tank is an 80,000 gallon divided hold tank (shown on Figure 11.2-3) with suitable biological shielding. It is located in the south yard near the decontamination building. The blowdown liquid in this tank is processed as liquid waste. The tank is also used for holdup and processing of other liquid waste.

Additional holdup capacity is provided by blowdown lines connected to the Unit 2 holding tanks.

A ruptured steam generator tube accident analysis is covered in Section 14.2.4. Technical Specifications require plant shutdown if primary to secondary system leakage exceeds RCS leakage limits.

10.3.8.3 Performance Analysis

In the event of a steam generator tube leak, the radiation monitors downstream of the blowdown heat exchangers will monitor for increased radioactivity. Radiation monitor (RM-SV-100) in the air ejector discharge line causes noncondensable gases from the condenser to be diverted from the gaseous waste disposal system to the containment in the event of a high-high radiation level. Loss of power or air to these valves causes them to fail safe.

In the event of a high-energy line break (HELB) outside containment, two safety-related trip valves in series have been added to each blowdown line. These valves (TV-BD-101-A1, A2, B1, B2, C1, and C2) will isolate steam generator blowdown within 15 seconds after ambient temperature in the Auxiliary and Safeguards Buildings exceeds 111°F (isolation time includes sensor response time, signal processing time, and valve stroke time). Reducing orifices (RO-BD-109A, B, and C) limits the energy release in those areas without ambient monitors so the environmental qualification envelope in those areas with vital equipment is maintained.

10.3.8.4 Tests and Inspections

The secondary vent and drain systems are in continual use and require no special periodic testing and inspection. However, the trip valves installed in these systems, which are part of the containment isolation system, provide HELB isolation, or which trip on high-high radiation level, are tested periodically.

10.3.9 Turbine Plant Component Cooling Water System

The turbine plant cooling water system supplies cooling water to steam and power conversion system equipment. The system is a closed loop system using treated condensate as cooling water.

10.3.9.1 Design Bases

Heat removed by the closed loop turbine plant component cooling water system is transferred to the circulating water system (Section 10.3.4) through component cooling water heat exchangers. A temperature controlled bypass around these heat exchangers maintains the cooling water supply temperature. The cooling water is circulated through the shell side of the component cooling water heat exchangers and through the various equipment coolers by motor-driven turbine plant component cooling water pumps.

The principal equipment served by the turbine plant component cooling water system is as follows:

1. Generator hydrogen coolers
2. Hydrogen seal oil coolers
3. Turbine oil coolers
4. Exciter cooler
5. EH cooler
6. Isolated phase bus duct air coolers

7. Station air compressors, each

8. Sample coolers

9. Condensate, feed and heater drain pumps

10. Vacuum priming pumps seal coolers, each

10.3.9.2 Description

The cooling water flow through the major equipment coolers, such as the hydrogen and oil coolers, is controlled automatically to maintain the cooler fluid at a constant temperature.

A head tank is provided to maintain a positive pressure at all points in the system. Makeup to the system is provided from the condensate pump discharge header. An alarm is actuated upon low level in the head tank.

River water is pumped from the Ohio River through the tube side of the turbine plant component cooling water heat exchangers and returned to the main condenser circulating water outlet line.

10.3.9.3 Performance Analysis

The station air compressors are the only equipment requiring cooling water when the turbine plant cooling water system is shut down. These compressors are required for maintenance reasons only at this time. The compressors are not safety related, as all air-operated valves are fail safe. Under this condition, air compressor cooling circuit & aftercooler cooling water is supplied from the filtered water storage tank via filtered water system pumps.

10.3.9.4 Tests and Inspections

Pumps and heat exchangers are rotated between duty and standby or periodically test run.

REFERENCES FOR SECTION 10.3

1. Deleted by Revision 23.

2. Letter from J. D. Sieber (Duquesne Light Company) to A. W. DeAgazio (Nuclear Regulatory Commission), Subject: Main Feedwater Piping Elbow Cracking and Misalignment - TAC 79769 (June 1991).

BVPS UFSAR UNIT 1

TABLES FOR SECTION 10

Table 10.3-1

COOLING TOWER DESIGN PARAMETERS

1.	Type	Natural Draft
2.	Flow, gpm	507,400
3.	Range, F	25.5
4.	Approach, F	16
5.	Dry bulb temperature, F	87
6.	Wet bulb temperature, F	74
7.	Exit air volume, cfm	35×10^6
8.	Exit air temperature, F	106
9.	Evaporation loss, gpm	10,500
10.	Drift loss, percent	0.05
11.	Pumping head, ft	68.8
12.	Top diameter, ft	219
13.	Height, ft	501
14.	Bottom diameter, ft	446

Table 10.3-2

COOLING TOWER PUMP
DESIGN PARAMETERS

1.	Number of pumps	4
2.	Capacity, gpm each	126,850
3.	Type of pump	vertical, dry pit
4.	TDH, ft	96.4

Table 10.3-3

CIRCULATING WATER SYSTEM
DESIGN PARAMETERS

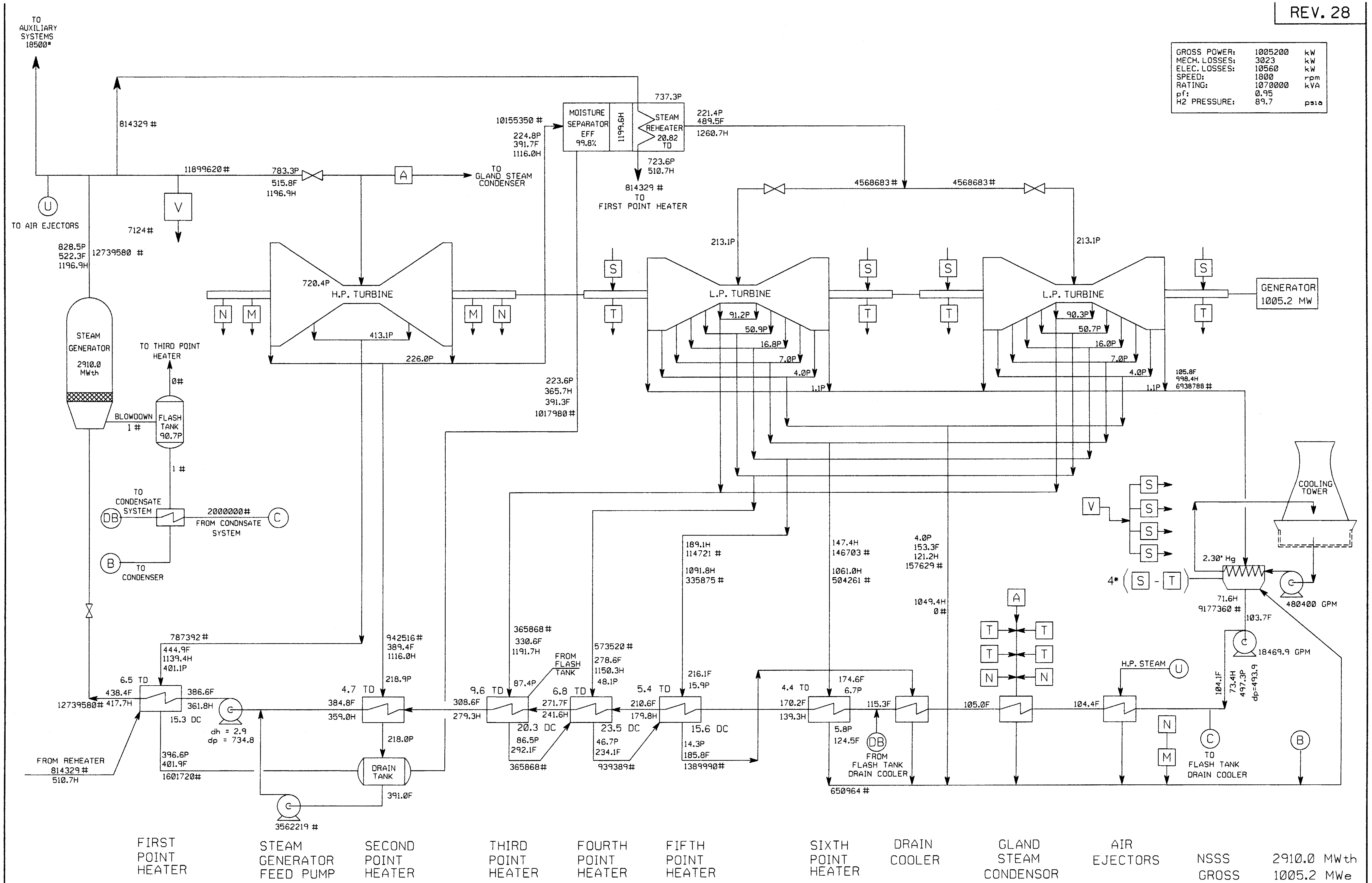
	Component	Design Pressure (psig)	Operating Pressure (psig)
1.	Steel pipe under turbine bldg. 108 inch diameter or 78 inch diameter	30	9 (max)
2.	Concrete pipe between turbine bldg. and pump house 108 inch diameter	na(1)	na(1)
3.	Main Condenser inlet/outlet valves 78 inches	50	3.7/-2.1
4.	Main condenser inlet/outlet expansion joints 78 inch diameter	40	3.7/-2.1
5.	Cooling tower pump suction valves	150	9
6.	Cooling tower pump discharge valves	150	43.2
7.	Cooling tower pump suction expansion joints	45	9
8.	Cooling tower pump discharge expansion joints	75	43.2
9.	Steel pipe at cooling tower pump house	90-180	9-43.2

(1) Gravity flow

Table 10.3-4

CONDENSER DESIGN PARAMETERS

1.	Steam condensed, lb/hr	6,700,000
2.	Circulating water flow rate, gpm	480,000
3.	Surface area, sq ft	720,000
4.	Number of tubes	67,924
5.	Tube material, Type	SEA-CURE (A268-82) UNS 44660
6.	Tube OD, inches	0.75
7.	Effective length per tube, ft	54
8.	Back pressure, inches Hg abs	2.0
9.	Hotwell temperature, F	101



LEGEND

#-MASS FLOW LB/HR
P-PRESSURE PSIA
H-ENTHALPY BTU/LB
T-TEMPERATURE DEG F

LEAKAGE FLOW

A - 2120#
M - 5458.3#
N - 666.00#
S - 2311.1#
T - 808.88#
V - 7124#

MSR VALUES ARE AVERAGE/TOTAL OF FOUR MSR's

FW HEATER TEMPERATURES AND ENTHALPIES APPLY TO STRING A
STRING B CONDITIONS ARE SLIGHTLY DIFFERENT.

FIGURE 10.2-1
HEAT BALANCE
(REF. CALC. 8700-DMC-1426 REV.1 ADD.5)
BEAVER VALLEY POWER STATION UNIT 1
UPDATED SAFETY ANALYSIS REPORT

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REV. 33

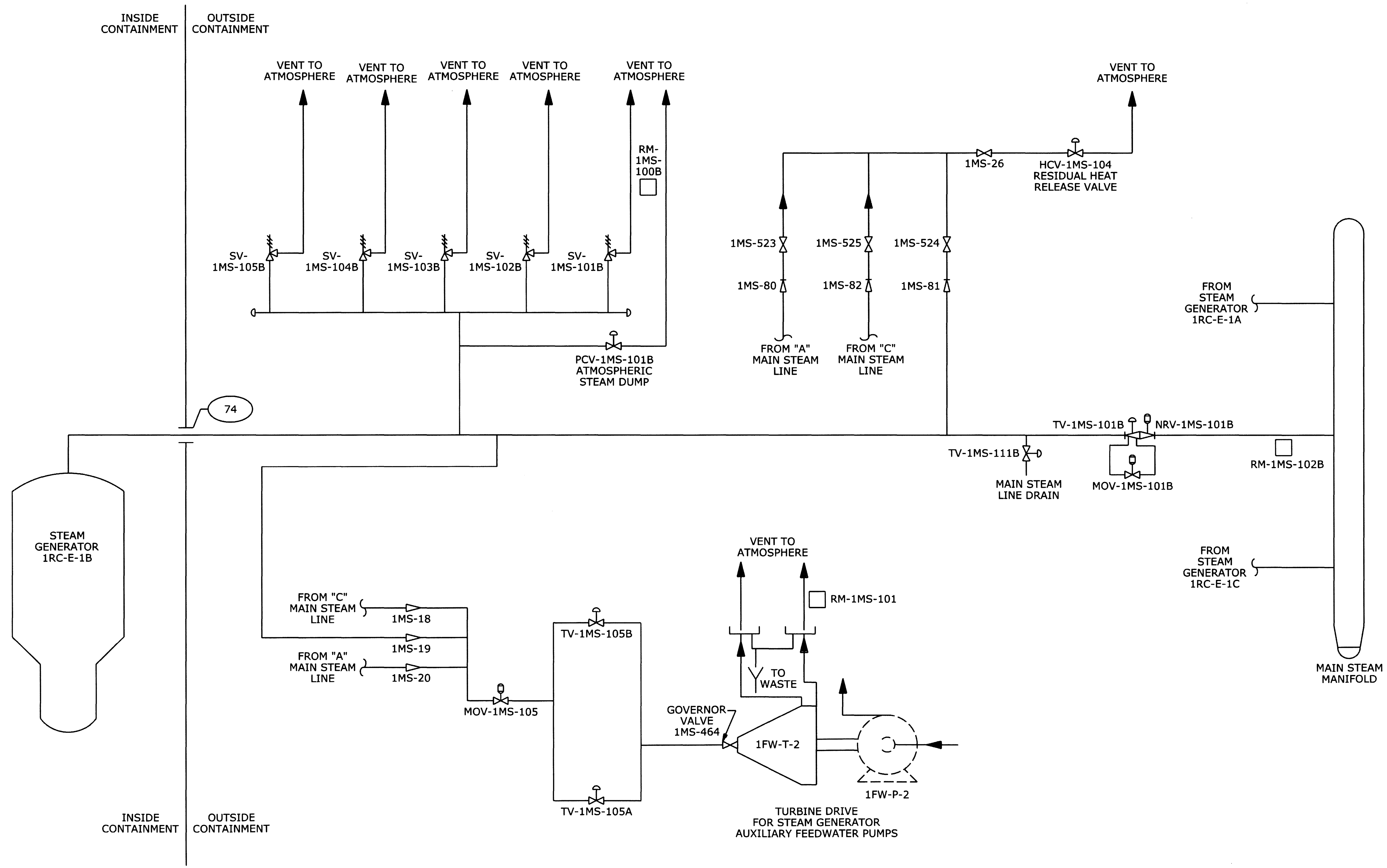


FIGURE 10.3-1
MAIN STEAM SYSTEM SHEET 1

REFERENCE: STATION DRAWING BV1 RM-0421-001
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

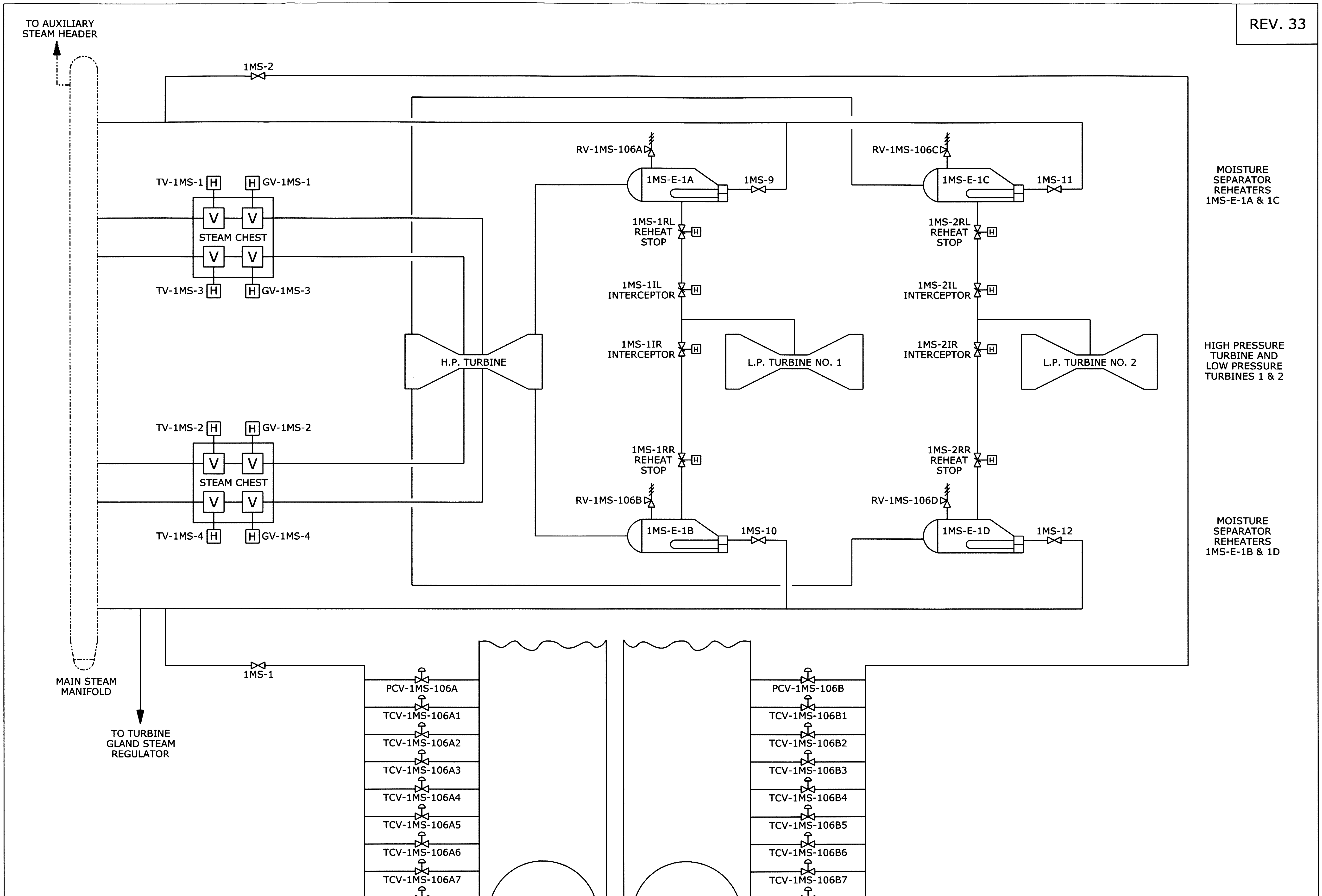
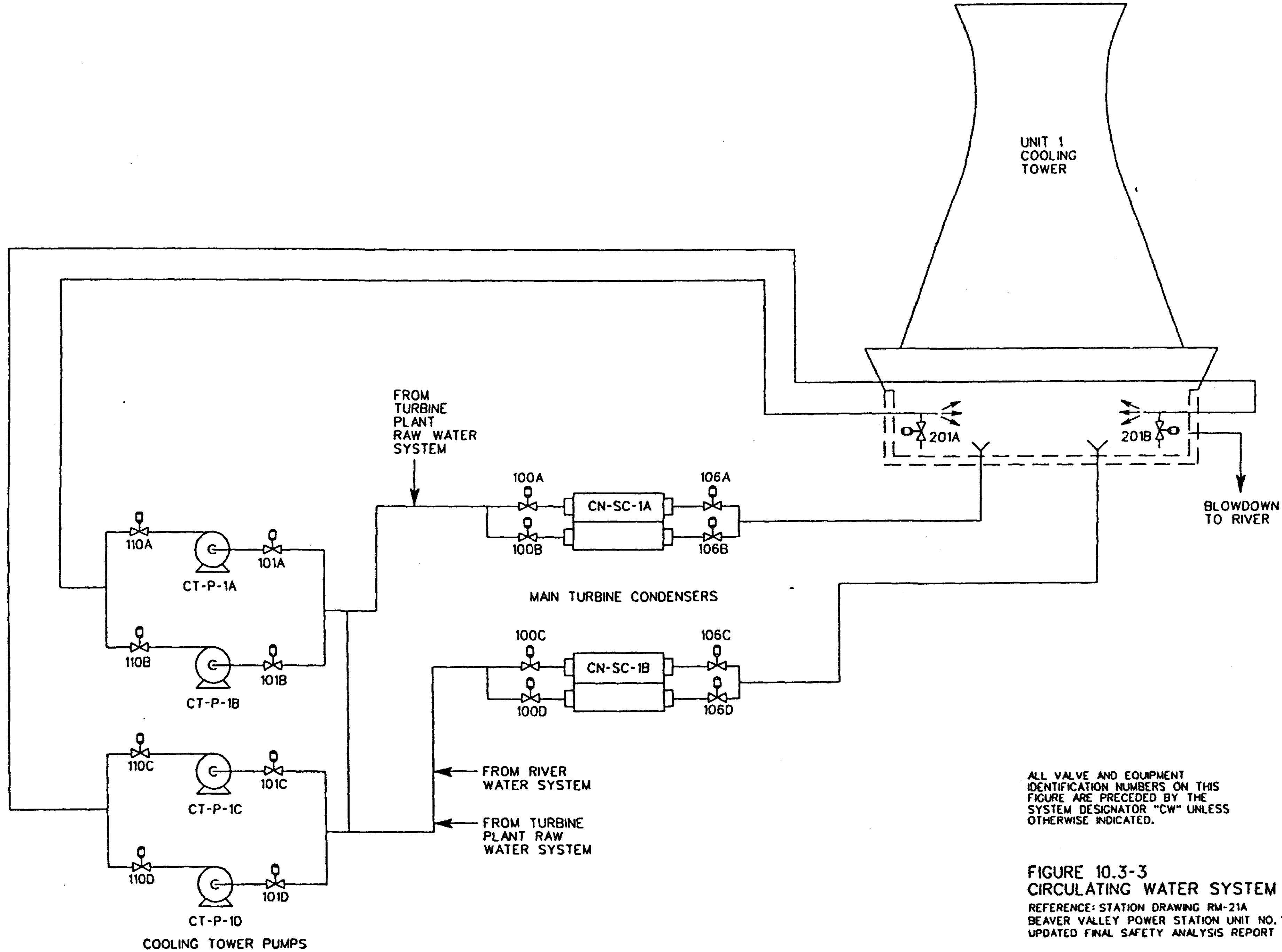


FIGURE 10.3-2
MAIN STEAM SYSTEM SHEET 2

REFERENCE: STATION DRAWING BV1 RM-0421-002
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REV. 18



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "CW" UNLESS OTHERWISE INDICATED.

FIGURE 10.3-3
CIRCULATING WATER SYSTEM

REFERENCE: STATION DRAWING RM-21A
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

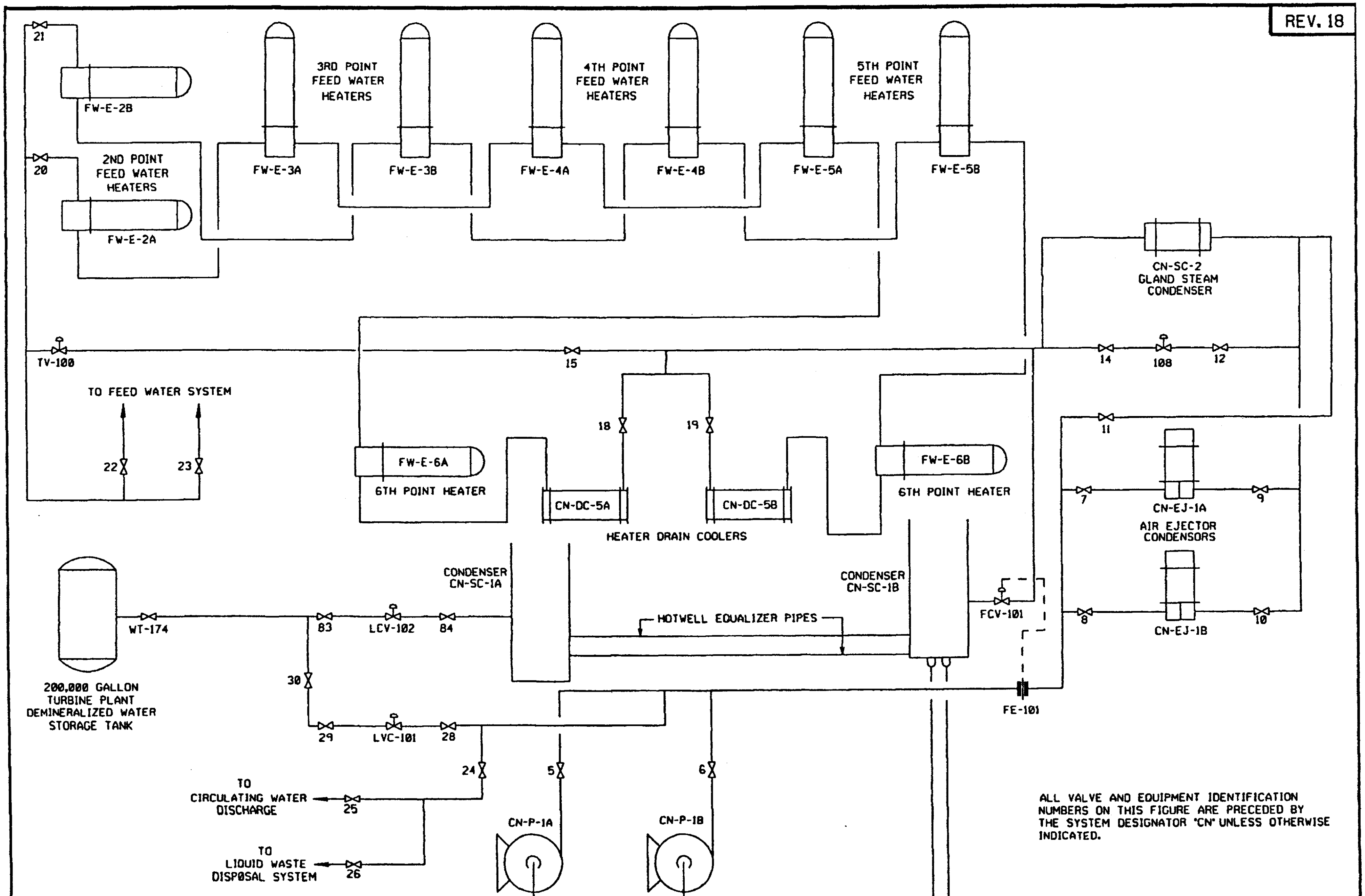


FIGURE 10.3-4
CONDENSATE SYSTEM
REFERENCE: STATION DRAWING RM-17A
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

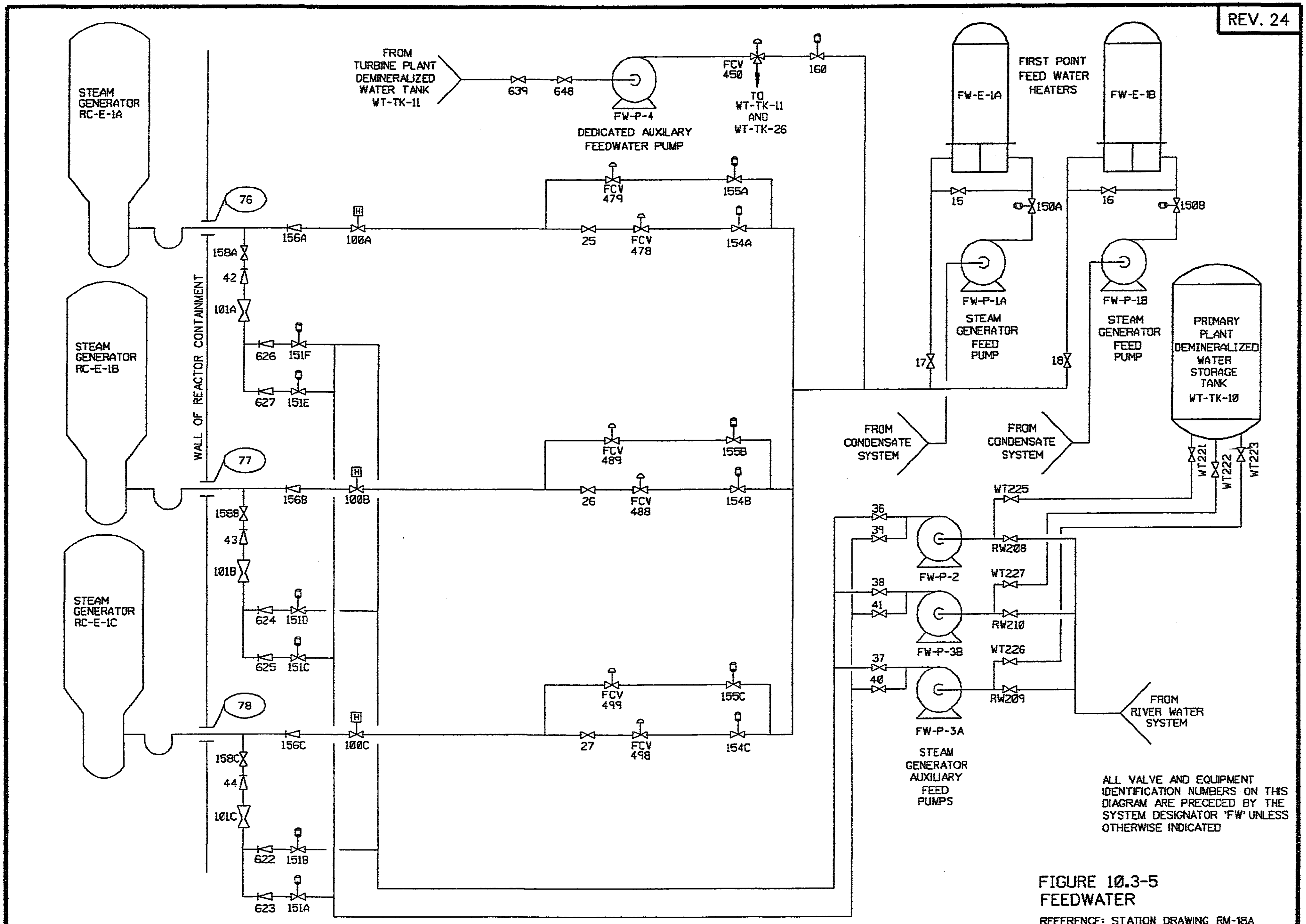


FIGURE 10.3-5
FEEDWATER

REFERENCE: STATION DRAWING RM-18A
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

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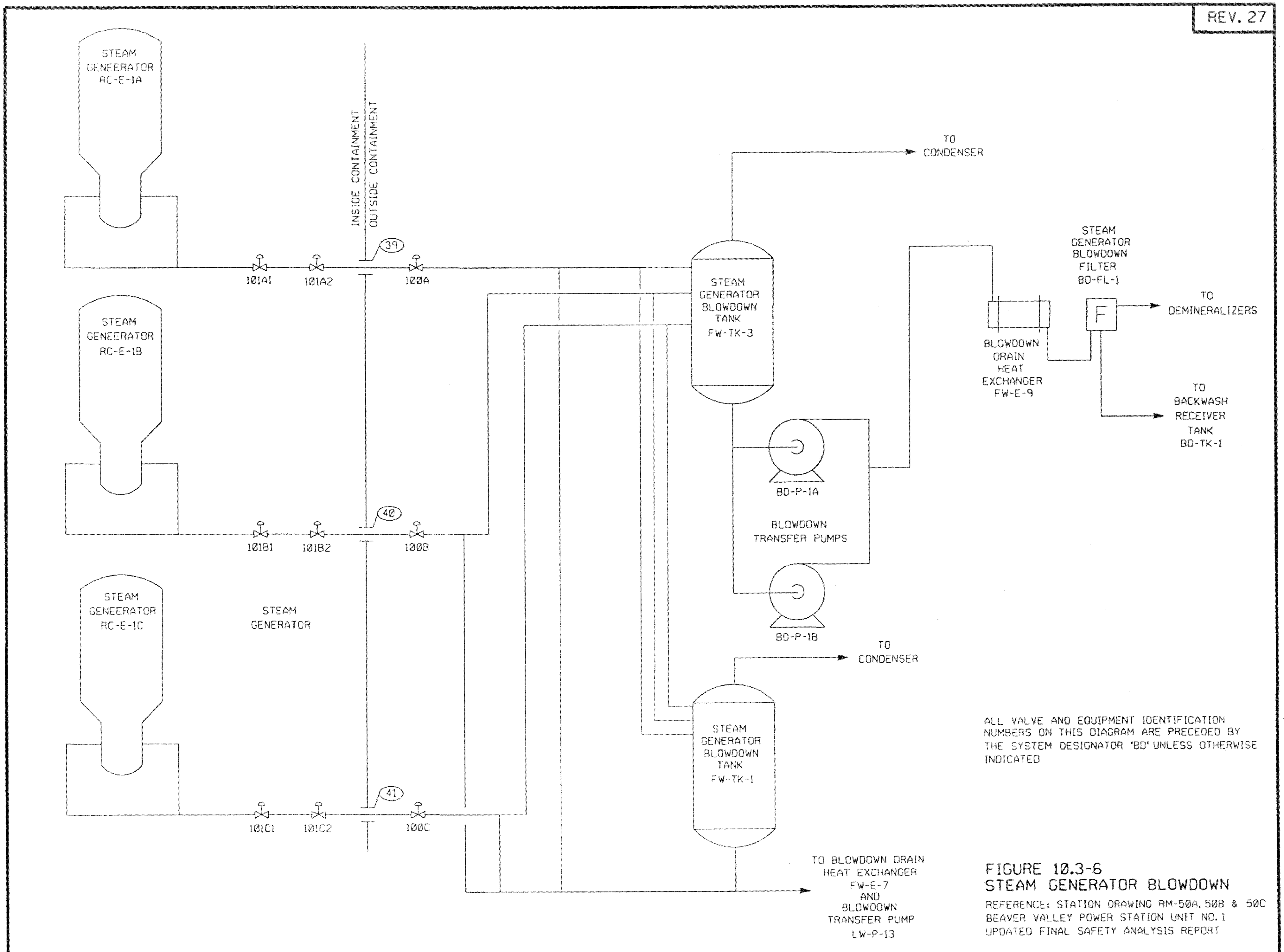

FIGURE 10.3-6
STEAM GENERATOR BLOWDOWN

REFERENCE: STATION DRAWING RM-50A, 50B & 50C
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT