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CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

This section describes the steam and power conversion system which is designed to receive steam generated by the steam generators (Chapter 5) and to produce electrical power. The major components of the steam and power conversion system are: turbine-generator-exciter complete with moisture separators/reheaters, main steam, main condenser, condensate pumps, condenser air removal system, turbine gland sealing system, turbine bypass steam system, condensate demineralizer system, heater drain pumps, steam generator feed pumps, feedwater heaters, and drain coolers. The heat rejected in the main condenser is removed by the circulating water system.

The steam produced in the steam generators is passed through the high-pressure turbine, where the steam is expanded, and then exhausted to the moisture separators/reheaters. The moisture separators reduce the moisture content of the steam, and the reheaters superheat the steam before it enters the low-pressure turbines. From the low-pressure turbine, the steam is exhausted into the main condenser, where it is condensed and deaerated, and then returned to the closed loop cycle as condensate. A portion of the main steam is fed to the reheaters. This main steam is condensed in the reheater and cascaded to the highest pressure heater. A small part of the main steam supply is continuously used by the auxiliary steam system, which supplies miscellaneous loads including the air ejectors and gland steam system. The condensate pumps take suction from the condenser hotwell, discharge through the condensate polishing system, the air ejector intercondensers, gland steam condenser, drain coolers, and five stages of low-pressure feedwater heaters to the suction of the steam generator feed pumps. The feed pumps supply feedwater through one stage of high-pressure feedwater heaters to the steam generators. Steam and hot water for the feedwater heating cycle is supplied from the turbine extractions and moisture separator/reheater drains, respectively.

Under normal operation, the turbine uses all the steam produced in the steam generators except for auxiliary steam uses. However, an automatic pressure/temperature controlling turbine bypass system (TBS) is provided to discharge excess steam, greater than 40 percent of full load steam flow, directly to the main condenser. The TBS is designed to control steam generator pressure by dumping excess steam during start-up, shutdown, and transient periods when steam generation exceeds turbine steam requirements.

The following design features are safety-related:

1. Main steam lines from the steam generator up to and including the main steam isolation trip valves.

2. Feedwater piping from the steam generators up to and including the isolation valve outside the containment.

3. All components of the auxiliary feedwater system.

4. Steam generator blowdown lines from the steam generators up to and including the isolation valves outside the containment.

The turbine generator has a maximum calculated capability as depicted on Figure 10.1-1 when operating with six stages of feedwater heating.

The plant heat balance at the Nuclear Steam Supply System (NSSS) thermal power of 2910 MWt is shown on Figure 10.1-1. Also, important design and performance characteristics are provided in Table 10.1-1.

The following sections describe the equipment and systems required for the steam and power conversion system:

10.2	Turbine-Generator
10.3	Main Steam Supply System
10.4.1	Main Condenser
10.4.2	Condenser Evacuation System
10.4.3	Turbine Gland Sealing System
10.4.4	Turbine Bypass System
10.4.5	Circulating Water System
10.4.6	Condensate Cleanup System
10.4.7	Condensate and Feedwater Systems
10.4.8	Steam Generator Blowdown System
10.4.9	Auxiliary Feedwater System
10.4.10	Auxiliary Steam and Condensate Systems
10.4.11	Extraction Steam System

Tables for Section 10.1

TABLE 10.1-1

STEAM AND POWER CONVERSION SYSTEM
PRINCIPAL DESIGN AND PERFORMANCE CHARACTERISTICS

Item	Design and Performance Characteristics
Turbine-generator unit (Section 10.2)	
Turbine	1,009 Mwe rating at the NSSS thermal power of 2910 MWt, 1,800 rpm, tandem compound, four flow, 13.9m^2 annulus area, last-stage buckets, with single-stage reheat, at 2.30 in Hg absolute exhaust pressure and 0 percent makeup
Generator	1,070,000 kVA, 1,800 rpm, direct-connected, three-phase, 60 Hz, 22,000 V, hydrogen inner-cooled, rated at 0.92 pf, and 75 psig hydrogen pressure
Exciter	3,900 kW, 525 V, direct connected and brushless
Control	Electro-hydraulic control (EHC)
Overspeed Protection	Redundant speed control systems 1. Normal and transient EHC speed control system 2. Auto stop trip system 3. Overspeed protection controller 4. Mechanical overspeed trip weight
Main steam supply system (Section 10.3) between the steam generator and the isolation trip valves outside the containment	Piping and valves up to and including isolation trip valves outside containment: ASME Section III, Code Class 2 and Seismic Category I
Main steam supply system from the isolation trip valves to outside the main steam valve house	Piping and valves: ANSI B31.1, Seismic Category I

TABLE 10.1-1 (Cont)

Item	Design and Performance Characteristics
Main steam supply system outside the main steam valve house	Piping and valves: ANSI B31.1, nonseismic
Main Condenser (Section 10.4.1)	Twin-shell, single pass, 720,000 ft^2 surface area, equalizing ducts between steam sections and hot well section
Condenser air removal system (Section 10.4.2)	Two half-capacity vacuum priming ejectors for initial shell-side air removal, two full-capacity steam jet air ejectors for maintaining vacuum. Steam and noncondensibles go to the gaseous waste disposal system for the air ejectors, and directly to the atmosphere for the vacuum priming ejectors. Piping and valves: ANSI B31.1
Turbine gland sealing system (Section 10.4.3)	Steam is supplied either from the main steam supply system directly or via the auxiliary steam system. Piping and valves: ANSI B31.1
Turbine bypass system (Section 10.4.4)	Flow capacity of greater than 40 percent of full load steam flow. Piping and valves: ANSI B31.1
Circulating water system (Section 10.4.5)	Four 25 percent capacity circulating water pumps, one hyperbolic natural draft cooling tower, and a fabricated-steel piping system
Condensate demineralizer system (Section 10.4.6)	1. One train of five ion exchangers, designed for four normally operating. The demineralizers remove ion and particulate contaminates from the condensate and feedwater cycle.
	2. Piping: ANSI B31.1 Pressure vessels: ASME Section VIII
Condensate and feedwater systems (Section 10.4.7)	1. Three half-capacity motor-driven condensate pumps, two air ejector intercondensers, one gland steam condenser, five stages of low-pressure regenerative feedwater heaters, including one separate drain cooler, all divided into two strings of half-capacity heaters, two half-capacity motor-driven feed pumps, and one stage of

TABLE 10.1-1 (Cont)

Item	Design and Performance Characteristics
	two half-capacity high-pressure feedwater heaters
	2. Piping and valves from the hotwell up to but not including the containment isolation valves outside the containment structure: ANSI B31.1. Piping and valves from the containment isolation valves to the steam generators: ASME Section III, Code Class 2

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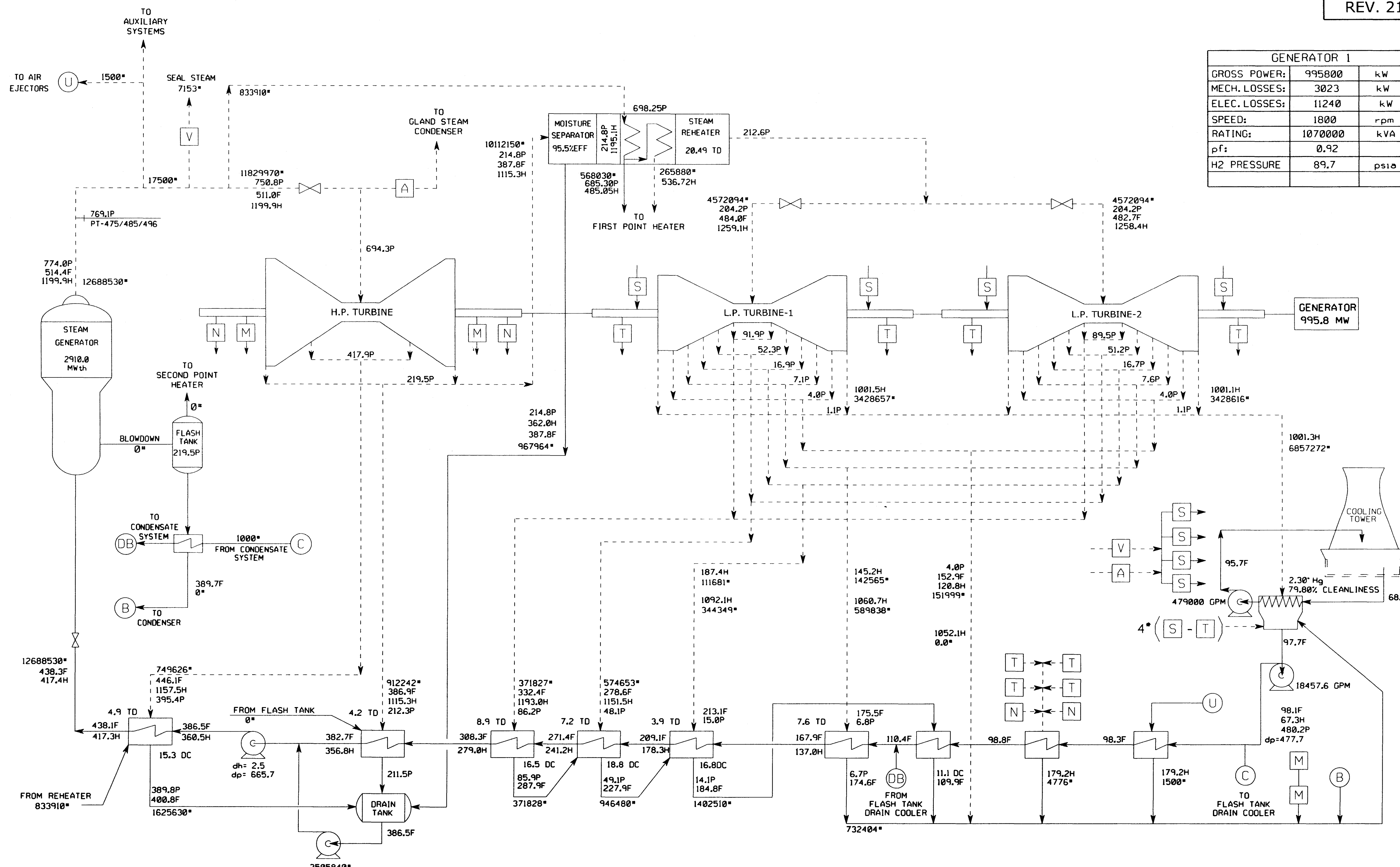


GENERATOR 1		
GROSS POWER:	995800	kW
MECH. LOSSES:	3023	kW
ELEC. LOSSES:	11240	kW
SPEED:	1800	rpm
RATING:	1070000	kVA
pf:	0.92	
H2 PRESSURE	89.7	psia

FIRST POINT HEATER — STEAM GENERATOR FEED PUMP — SECOND POINT HEATER — THIRD POINT HEATER — FOURTH POINT HEATER — FIFTH POINT HEATER — SIXTH POINT HEATER — DRAIN COOLER — GLAND STEAM CONDENSOR — AIR EJECTORS

RTP	2900.0 MWt
NSSS	2910.0 MWt
GROSS	995.8 MW

NON SAFETY RELATED, QA CAT II

LEGEND

-MASS FLOW, LBS/HR
P-PRESSURE, PSIA
H-ENTHALPY, BTU/LB
F-TEMPERATURE, DEG F

LEAKAGE FLOW

A - 2052#
M - 5228.8#
N - 673.00#
S - 2301.4#
T - 857.51#
V - 7153#

2007 UPRATE HP TURBINE
2012 REPLACEMENT LP TURBINE

MSR VALUES ARE AVERAGE/TOTAL OF FOUR MSRs.
FW HEATER TEMPERATURES AND ENTHALPIES ARE STRING A. STRING B SLIGHTLY DIFFERENT.

FIGURE 10.1-1
HEAT BALANCE DIAGRAM
2910 MWt NSSS, 2.3 inHga. 0.92 PF
(REF. CALCULATION 10080-DMC-0742 REV 1 ADD 2)

BEAVER VALLEY POWER STATION UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

10.2 TURBINE GENERATOR

10.2.1 Design Bases

1. The turbine generator (TG) is a 1,800 rpm, tandem compound, four-flow, reheat steam turbine with 44 inch last stage blades and a single-stage of reheat. The output of the TG at the NSSS thermal power of 2910 MWt is shown on Figure 10.1-1. During faulted and emergency conditions, the turbine is shut down.

2. The generator is 1,800 rpm, direct-connected, three-phase wye-connected, 60 Hz, 22,000 V, hydrogen inner-cooled, synchronous generator rated at 0.92 pf, 0.61 short circuit ratio, and a maximum hydrogen pressure of 75 psig, and an output of 1,070,000 kVA at turbine VWO conditions.

3. The brushless excitation system consists of a 60 Hz, 1,800 rpm air-cooled ac exciter and a rectifier assembly mounted on a common shaft. The exciter is rated for a maximum output of 3,900 kW at 525 V.

4. The TG is designed in accordance with Regulatory Guide 1.68, as it relates to preoperational and start-up testing of system components, equipment, and systems.

5. The TG unit control is through an electro-hydraulic control (EHC) system capable of controlling the speed, load, and steam flow under steady-state and transient conditions. The intended mode of operation is for base-loaded conditions.

6. The TG unit is designed in accordance with General Design Criterion 4, as it relates to the protection of structures, systems, and components important to safety from the effects of turbine missiles by providing a redundant turbine overspeed protection system.

7. The TG unit is a Westinghouse Electric Corporation (Westinghouse) design and is built in accordance with Westinghouse and industry standards and codes. The moisture separators/reheaters are built in accordance with ASME Section VIII.

8. The TG is capable of increasing or decreasing electrical load at a rate consistent with the requirements of the nuclear steam supply system manufacturer (Section 7.7) and the turbine manufacturer's loading rate recommendations. However, under emergency conditions, the TG can accept greater load changes.

10.2.2 Description

The TG system consists of one double-flow high pressure casing, two double-flow low pressure casings, four moisture separators/reheaters, four high pressure inlet throttle valves, four high pressure inlet governing valves, four low pressure reheat stop valves, four low pressure intercept valves, an EHC, provisions for extracting steam for six stages of feedwater heating, a lubricating oil system, gland steam sealing system, turbine turning gear system, generator seal oil system, and hydrogen cooling system.

The turbine steam valves and piping are shown on Figure 10.2-1. Each high pressure steamline to the high pressure turbine contains automatically- or manually-controlled throttle valves for wide range speed control during start-up, and governor valves for controlling steam flow for synchronizing and load control. These valves are located in the steam chest just upstream of the high pressure turbine inlet. The reheat stop and intercept valves are located in the crossover piping between the moisture separators/reheaters and low pressure turbine inlet. These valves are of the on-off type and offer redundant, positive isolation of the steam flow path to the low pressure turbine.

Steam exhausting from the high pressure turbine flows to the moisture separators/reheaters, which uses chevron separator vanes for moisture separation and integral live steam U-tube reheaters with Type 439 stainless steel tubes. The moisture separators/reheaters are designed in accordance with ASME Section VIII. Each of the four steamlines between the reheater outlet and low pressure turbine inlet is provided with a crossover stop valve and a crossover intercept valve in series. These valves, operated by the turbine electro-hydraulic control system, function to prevent turbine overspeed. A safety valve is installed on each moisture separator/reheater to protect the separators/reheaters and crossover system from overpressure. The safety valves are designed to pass the flow resulting from closure of the crossover stop or intercept valves with the main turbine throttle valves wide open. These valves discharge to the condenser.

There are two parallel flow paths to each of the two low pressure casings, resulting in a total of four steam flow paths.

In the event of a large scale, external electrical load decrease of up to 85 to 100 percent, the turbine bypass system (TBS) relieves main steam directly to the condenser, thus it is capable of preventing a reactor or turbine trip and the lifting of the main steam safety valves. The bypass line provides a capacity of greater than 40 percent of full load steam. Turbine bypass control is covered more fully in Section 7.7.1.8 and TBS capability and operation is covered in Section 10.4.4.

Six stages of extraction steam are provided on the turbine. Redundant extraction steam isolation valves are located in the extraction steamlines to prevent a turbine overspeed after a trip. They consist of a spring-assisted, air-actuated swing check valve, (nonreturn valve) and a motor-operated gate valve in series. Upon a turbine trip, the nonreturn valve (NRV), which is equipped with a spring-assisted, side closing cylinder for positive closing, is closed by venting the air in the cylinder and spring action. The extraction steam system is described more fully in Section 10.4.11.

The TG lubricating oil system consists of an oil reservoir, a shaft-driven main and six motor-driven oil pumps, vapor extractor, oil coolers, centrifuge type lube oil purifier, associated piping, and various control devices. A particulate and water coalescing type lube oil purifier was added subsequent to obtaining the plant operating license. The reservoir is equipped with high and low level switches, temperature indicators, and a local level indicator.

During normal unit operation, lubricating oil is supplied by an oil ejector mounted inside the oil reservoir. The ejector discharge pressure is sufficient to assure a positive supply of lubricating oil to all bearings. Additionally, the ejector maintains the main (shaft-driven) oil pump net positive suction head, which in turn operates the ejector.

An ac motor-driven bearing oil pump and an ac motor-driven high pressure generator seal oil backup pump are provided, each having a dual function. The bearing oil pump serves to provide lubricating oil to the bearings when the unit is on turning gear and acts as a backup should the main oil pump fail. The high pressure generator seal oil backup pump serves to provide high pressure oil to latch the mechanical overspeed trip mechanism during start-up and acts as a seal oil backup for the generator (Section 10.2.2.4). A pressure switch automatically starts the high pressure generator seal oil pump and the bearing oil pump when bearing oil pressure is low.

A dc motor-driven emergency oil pump serves as an emergency backup for the ac motor-driven bearing oil pump when the ac power is lost. A pressure switch automatically starts the dc motor-driven oil pump when the bearing oil pressure is low.

All of the pumps are controlled from the main control room via individual control switches.

The pressure switches controlling the start of the bearing oil pump, the high pressure generator seal oil backup pump, and dc emergency oil pump will automatically start the pumps on falling pressure. Once energized, the pumps must be shut down manually. A test valve is provided to test the cut-in points of the pumps. The test can be made during normal operation.

Three bearing oil lift pumps provide lift oil to the low pressure bearings to meet the requirements for placing the unit on turning gear. Bearing oil pressure must be at least 5 psig to permit starting the turning gear motor.

The Beaver Valley Power Station - Unit 2 (BVPS-2) turbine oil reservoir receives its oil supply from the Beaver Valley Power Station - Unit 1 (BVPS-1) lubricating oil storage tank. The BVPS-1 fill pump discharge is piped to supply oil to either the BVPS-1 or BVPS-2 turbine oil reservoirs. This pump has a capacity of 100 gpm at 80 psig discharge pressure and takes its suction from the BVPS-1 lubricating oil storage tank.

The temperature of the oil supply to the bearings is automatically controlled by the cooling water flow regulator valve and temperature control device located in the oil piping.

A bypass stream of turbine lubricating oil flows continuously through an oil conditioner to remove any water and other impurities.

One of the lubricating oil purifiers is an integral centrifuge unit consisting of a feed pump, a centrifuge type separator, and controls. A supply line from the turbine oil reservoir feeds the oil to the purifier where it is cleaned and then returned back to the turbine oil reservoir. The purifier has a purifying capacity of 3,000 gallons per hour (gph).

The inlet line to the purifier is provided with a loop seal arrangement, complete with a sight glass, to prevent siphoning of oil from the reservoir.

Water from the demineralized water distribution system is used to seal the purifier against oil spillage. A flow-type emergency breakover switch mounted on the water outlet of the purifier allows for normal water discharge and prevents excessive flow of water or oil.

The purifier is provided with a bowl drain recovery kit such that when the purifier is shut down, the contents of the self-draining bowl can be reclaimed. Recovered oil is reintroduced to the purifier feed line when the unit is started.

10.2.2.1 Turbine Control System

10.2.2.1.1 Normal Operation

The TG system is equipped with an analog type EHC system to regulate turbine generator speed, load, and steam flow, and to protect the turbine from reaching a destructive overspeed condition. The EHC system consists of a solid-state electronic control cabinet, an operators panel, steam valve servo actuators, high pressure fluid control system, and a lube oil and associated electro-hydraulic emergency trip system.

Valve opening activation is provided by a high pressure hydraulic system (approximately 2000 psig). However, valve closure under emergency tripping is provided by powerful springs aided by steam forces when the high pressure hydraulic fluid is dumped from the piston by the tripping action.

During start-up, from turning gear to rated speed, the EHC system is in a manual wide-range speed control mode. Speed control is accomplished by increasing the speed demand reference signal manually to bring the shaft to rated speed at a controlled and selectable rate. The resolution of the controller with respect to actual speed versus set speed is 1.0 rpm. When the turbine reaches rated speed and the main generator circuit breaker is closed, the EHC system changes from a speed controller to a load controller. The EHC system provides the ability to increase or decrease electrical load at a controlled and selectable rate with a resolution of 0.1 percent load.

The control of the reactor and TG is accomplished from the main control room, which contains all instrumentation and control equipment required. The control system allows BVPS-2 to accept step load increases of 10 percent and ramp load increases of 5 percent/min over a load range of 15 to 100 percent power. For reactor power levels below the P-9 permissive setpoint, the unit is designed to accept a turbine trip without initiating a reactor trip; however, the Plant Technical Specifications require an anticipatory reactor trip following turbine trips at reactor power levels above the P-9 permissive setpoint. The turbine bypass steam dump capacity permits a 50 percent external load rejection from full load without a turbine or reactor trip. The control of the reactor with turbine is covered more fully in Section 7.7. The turbine bypass system's capability is covered more fully in Section 10.4.4.

The Westinghouse analog EHC system and electromechanical trip system include three separate speed sensors, mounted on the turbine stub shaft located in the turbine front pedestal as follows:

1. Mechanical overspeed trip weight (spring-loaded),

2. Electro-magnetic pickup for main speed governing channel, and

3. Electro-magnetic pickup for overspeed protection control channel. (This pickup uses the same toothed wheel as item 2.)

10.2.2.1.2 Turbine Trip System

The electro-hydraulic emergency trip system consists of an emergency trip block, two test blocks mounted on the governor pedestal, a cabinet containing all the electrical and electronic hardware, a remote trip test panel, and main control board-mounted trip pushbuttons for manual tripping. The emergency trip system offers a redundant overspeed protection (Section 10.2.2.1.3) via electro-hydraulic and mechanically-actuated systems, an auto stop trip (AST) system which monitors various TG parameters, an overspeed protection controller (OPC) which monitors turbine speed and load, and a mechanical overspeed trip weight. The system also offers provisions for detection and diagnosis of failed devices, and provisions for inservice maintenance and inspection.

Under normal conditions, the AST solenoid valves and the interface diaphragm valve are closed, blocking the path to drain off the auto-emergency trip header fluid. The pressure in the trip header line keeps the dump valves associated with each steam valve closed. Upon collapse of this pressure, the dump valve will unseat, causing the throttle valves, governor valves, intercept valves, and reheat stop valves to close in approximately 150 milliseconds.

The AST solenoid valves are separated into two channels, with two valves per channel, which are kept energized from separate relay trains in the emergency trip system cabinet. If a trip contingency should occur, at least one valve from each channel must function to trip the turbine. However, each channel can be tested separately while on line without causing or preventing a valid trip. Since one valve from each channel must function to cause a trip, a single valve failure will neither cause a trip nor prevent a trip. The trip signals for which AST action will automatically trip the turbine are listed in Table 10.2-1.

Lubricating oil is used as the control medium for the interface diaphragm valve in the mechanical-hydraulic trip system. The diaphragm valve is the link between the lube oil system and the high pressure EHC system. Lube oil supplied to the valve acts to overcome the spring force to keep the valve closed. Upon a decay of the lube oil pressure the valve will unseat, causing the EHC fluid to drain, thus tripping the turbine.

10.2.2.1.3 Overspeed Protection

Overspeed protection is accomplished by the actuation of either the OPC, the mechanical overspeed trip weight, or by de-energizing the AST solenoid valves.

The OPC action will de-energize and open the solenoid-operated dump valves to collapse the OPC header pressure, thus closing the governor and interceptor valves. Check valves prevent collapse of the throttle and reheat stop valves header pressure. The OPC action will occur if the main generator breaker should open when the turbine is above 30 percent load or turbine overspeeds to 103 percent of rated speed. There are two OPC valves furnished for the system for redundant protection to prevent the failure of one valve from inhibiting a valid trip.

The mechanical overspeed trip weight uses a turbine shaft-mounted weight with its center line offset. During normal operation conditions, it is held in place against centrifugal force by a spring. When turbine speed reaches 111 percent of rated speed, increased centrifugal force overcomes the spring's compression and the weight moves outward with a snap action, releasing lube oil pressure on the diaphragm of the interface diaphragm valve. This drains the AST header pressure and closes all the throttle, governor, reheat stop and intercept valves.

The electro-hydraulic overspeed trip utilizes a speed pickup mounted adjacent to the turbine stub shaft. When the speed sensor indicates 111.5 percent of rated speed, the relay logic in the trip cabinet will be such that all four AST solenoid valves will open and trip the turbine.

The throttle and governor valves and the stop and intercept valves are arranged in a redundant fashion such that failure of one valve will not cause or prevent a turbine trip.

The extraction steam lines to the first through fifth point heaters contain nonreturn valves which are used to protect the turbine from a reverse flow. Each nonreturn valve is a swing check valve with a side-closing, spring-loaded cylinder. During normal operation, air pressure compresses this spring so the disc can swing freely. Upon receipt of a low AST header pressure signal or if the AST fluid-operated air pilot valve is vented (turbine tripped), the cylinder air pressure is released and the spring provides a rapid and positive closure of the check valve to prevent the fluid inventory in the down-stream heater from flashing and entering the turbine and providing energy to accelerate the turbine. The sixth point heaters have no nonreturn valves because there is a low inventory of fluid in these heaters so that overspeeding the turbine due to flashing in the heater is prevented.

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

The effects of turbine missiles on safety-related systems or components is not required to be analyzed because the probability of generating a turbine missile is acceptably low, as described in Section 3.5.1.3.

10.2.2.2 Turbine Gland Sealing System

The TG is sealed using labyrinth type shaft seals. The seal system is supplied with steam at 150 psig from the auxiliary steam system or 125 psig steam from the main steam system. Auxiliary steam is used during start-up and when main steam becomes available, the auxiliary steam supply is isolated.

The steam to the high pressure glands is maintained at 5 psig. Steam to the low pressure glands is maintained at 1 psig. Any excess steam is bypassed to the condenser through a spillover valve. The turbine gland sealing system is described more fully in Section 10.4.3.

10.2.2.3 Inspection and Testing Requirements

The main turbine throttle and governor valves and the intercept and reheat 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. Mechanical overspeed trip tests are performed on an 18 month frequency in accordance with the Licensing Requirements Manual.

10.2.2.4 Generator

The generator is sized to accept the output of the turbine. The generator is equipped with an excitation system, hydrogen control system (HCS), and a seal oil system. The generator terminals are connected to the main step up transformer and unit station service transformers through the isolated phase generator leads.

The air-cooled generator excitation system controls the voltage of the generator. The HCS includes pressure regulators, condition monitor for detection of thermally produced particulate, purity monitor for recording changes in gas density, temperature pressure transmitters, liquid detector, and water-cooled gas coolers. A circuit to supply and control the CO_2 is used during filling and purging operations to avoid explosive gas mixtures. A hydrogen seal oil system prevents hydrogen leakage or air inleakage through the generator shaft seals. This system includes pumps, controls, and a storage tank, and degasifies the oil before it is returned to the shaft seals.

10.2.2.5 Generator Hydrogen

The HCS is used to cool both the rotor and stator. The rating of the generator is a function of the hydrogen pressure which is normally 75 psig. The system includes pressure regulators for control of the hydrogen gas, and a circuit for supplying and controlling the carbon dioxide used in purging the generator during filling and degassing operations. To prevent hydrogen leakage through the generator shaft seals, a hydrogen seal oil system is provided. This system, which includes pumps, controls, and a storage tank, deaerates the oil before it is sent to the shaft seals.

Hydrogen is fed to the generator to maintain design pressure. A continuous hydrogen feed and bleed is controlled from the hydrogen control panel. Manual shutoff valves are provided in the turbine building. A flow meter in the hydrogen feed line to the generator and a flow meter in the vent line from the hydrogen control panel provide a means to measure leakage. The bulk storage facility also supplies hydrogen to the chemical and volume control tank (Section 9.3.4) and the boron recovery system (Section 9.3.4.6).

To avoid an explosive hydrogen-air mixture while charging the generator with hydrogen, carbon dioxide is used as the purging agent. While the generator is being filled with carbon dioxide, the percentage of carbon dioxide in the air/gas mixture is measured. Carbon dioxide is admitted to the generator until the percentage of carbon dioxide in the discharged gas is in excess of 70 percent. After purging the air from the generator, hydrogen is admitted purging the carbon dioxide. Purity of the hydrogen is monitored during operation to prevent an explosive mixture.

10.2.3 Turbine Rotors and Turbine Disc Integrity

The probability of a turbine disc failure has been assessed as part of the design of Siemens 13.9m^2 LP rotors. The risk from missiles created during a hypothetical turbine-generator failure on safety-related systems or components is discussed in Section 3.5.1.3. Integrity of the turbine discs and rotors is demonstrated by information provided in that section.

10.2.3.1 Materials Selection

Forgings produced for nuclear turbine discs and rotors are made to comply with Siemens specifications. The detailed materials specifications, fabrication history, and chemical analysis of the disc and rotor forgings are considered proprietary information of the turbine manufacturer, Siemens. More general ASTM specifications for discs and rotors (ASTM A-470 Class 7, and ASTM A-471 Class 4) do exist and may be used for guidance.

The forgings for the rotor shafts and disks are made from 3.5% nickel steel alloy. This material has been selected because of its low transition temperature. The forging technique has been advanced to minimize impurities. In addition to the ideal properties for low temperature LP turbine operation, the material also provides high yield strength at the temperature levels of the LP turbine inlet.

The disc material property requirements are listed in Table 10.2-2 along with the comparable ASTM requirements for ASTM A-470.

Any deviation from specification requirements for material composition and properties is evaluated by Siemens.

10.2.3.2 Fracture Toughness

The detailed materials specifications, fabrication history, and chemical analysis of the disc and rotor forgings are considered proprietary information of the turbine manufacturer, Siemens. The specific fracture toughness properties of the LP rotor discs are considered in the design of the turbine rotating components.

10.2.3.3 Pre-service Inspection

All rotors and discs are given pre-service inspections. In addition, Siemens utilizes ultrasonic inspection techniques for in-service inspection (ISI) of bores and keyways of shrunk-on discs in low pressure rotors. These techniques have undergone extensive development and qualification.

As a part of the inspection during manufacturing, discs are rough machined as close as practical to the forging drawing dimensions prior to heat treatment for properties. After heat treatment, the forgings are machined to the dimensions of the forgings drawing and stress relieved.

Low pressure and high pressure rotors are rough machined with maximum stock allowance prior to heat treatment and stress relieved.

After heat treatment, the rough machined disc is ultrasonically inspected on the flat surfaces of the hub and the rim (Figure 10.2-11). If ultrasonic indications are detected in the hub or the rim sections, additional ultrasonic testing may be required.

Centerline tangential stresses of a no-bore rotor are approximately half the tangential bore stresses of a bored rotor of the same size. This significantly increases integrity of no-bore rotor for a given size sonic indication compared to that of bored rotor of similar design.

The rotors are ultrasonically tested after heat treatment and rough machining. The sonic indications are either removed or evaluated to determine that they will not grow to a size that will compromise the integrity of the component during its service life.

The finished machined discs are fluorescent magnetic particle-inspected except for blade grooves. The disc is shrunk on to the shaft. After the disc is cooled, equally spaced, round-bottomed holes or keyways are drilled and reamed and are inspected using dye penetrant techniques. No indications are allowed in the bore or keyway regions.

Siemens HP rotors designed with KWU-technology integral shroud blades are spin-tested to 125 percent of rated speed to allow these Torsionally-preloaded blades to seat properly in the rotor grooves prior to final shroud seal land machining. The Siemens 13.9 m^2 LP Rotors are spin tested to 120 percent of rated speed. The maximum speed anticipated following a turbine trip from full load is less than 110 percent of rated speed.

10.2.3.4 Turbine Disc Design

The highest anticipated speed resulting from a loss of load is less than 110 percent of rated speed. The HP rotor is spin-tested at 125 percent of rated speed and LP rotors are spin-tested to 120 percent of rated speed.

Turbine shaft bearings are designed to withstand any combination of the normal operating loads, anticipated transients, and accidents resulting from a turbine trip. The low pressure rotor bearings are provided with lifting capabilities. During start-up and on turning gear high pressure, lubricating oil lifts the low pressure rotor to minimize wear on the bearing surface.

The rotors are designed so that the response levels at the natural frequency of the turbine shaft assemblies are controlled between 0 and 20 percent overspeed so as to cause no distress to the unit during operation.

The new no-bore HP rotor can be given a volumetric UT exam without removal of the rotor from the unit. The rims of the low pressure discs can also be inspected.

10.2.3.5 In-Service Inspection

The inservice inspection of the steam turbine assembly will be conducted to provide assurance against brittle failure of a disc at design overspeed. The inservice inspection will be performed approximately every 10 years, coincident with a plant shutdown. The inspection interval is based upon the probability of generating a turbine missile as a function of actual operating time. The operating time related probabilities associated with the BVPS-2 low pressure turbine rotor are shown on Figure 3.5-2.

The inservice inspection will consist of visual and surface examinations of couplings, coupling bolts, high pressure turbine rotor and discs, and low pressure turbine blades. Low pressure turbine rotors and discs will also be volumetrically examined using the inspection techniques described below.

Inspection Techniques

For the no-bore HP rotor, Siemens has developed a phased array volumetric UT technique that can detect off-center flaws in the forging. This capability allows improved characterization of internal flaw shape and size by measuring sound reflection of the same indication from several different angles.

Tangential Aim Technique

In the tangential aim technique, an ultrasonic transducer is mounted on a plexiglas block that sits on the disc hub (Figure 10.2-11). 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 (Figure 10.2-12). 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.

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.

The ISI program for throttle, governor, reheat stop and interceptor valves is in accordance with vendor recommendation of 15, 27, and 39 months after initial start-up of a turbine. In this program, some valves are inspected 12 to 15 months after start-up, others 24 to 27 months, and the remainder 36 to 39 months so that all valves are inspected at least once in the 39 months of operation following initial start-up. Throttle and reheat stop valves are inspected twice in this period. After this initial inspection program is completed, valves will be inspected periodically in accordance with Westinghouse recommendations.

Functional testing of the turbine steam inlet valves will be performed in accordance with the requirements contained in the Licensing Requirements Manual. These tests can be performed while the unit is carrying load. The purpose of the test is to ensure proper operation of the throttle, governor, reheat stop, and interceptor valves. The operation of these valves will be observed during the test by an operator stationed at the valves. Movements of the valves should be smooth and free. Jerky or intermittent motion may indicate a buildup of deposits on shafts.

10.2.3.6 High Temperature Properties

The operating temperatures of the high pressure rotors in turbines operating with light-water-reactors are below the creep rupture range. Creep rupture is, therefore, not considered to be a factor in assuring rotor integrity over the lifetime of the turbines.

10.2.4 Safety Evaluation

Beaver Valley Power Station - Unit 2 is a pressurized water reactor. As such, during normal operation the concentration of radioactive contaminants is minimal and no shielding is required for the TG, thus permitting unlimited access. There is no equipment required to be QA Category I (safety related) as listed in Table 3.2-1 in the turbine building, thus, rupturing of the connection joints between the low pressure casing and the condenser will not adversely affect any QA Category I equipment.

The turbine stop and control valves and reheat stop and intercept valves are arranged such that failure of any one valve will not cause an overspeed event.

10.2.5 References for Section 10.2

Westinghouse Electric Corporation 1971. Scientific Paper. 71-1E7-MSLRF-P1. MSTG-lP.

Siemens Technical Report EC-10079, BB-281-13.9m^2 Low Pressure Turbine Design Analysis Report for Beaver Valley Unit 2, Revision 1, June 15, 2010.

Siemens Technical Report CT-27472, Missile Report, Revision 2, August 5, 2011.

Tables for Section 10.2

TABLE 10.2-1

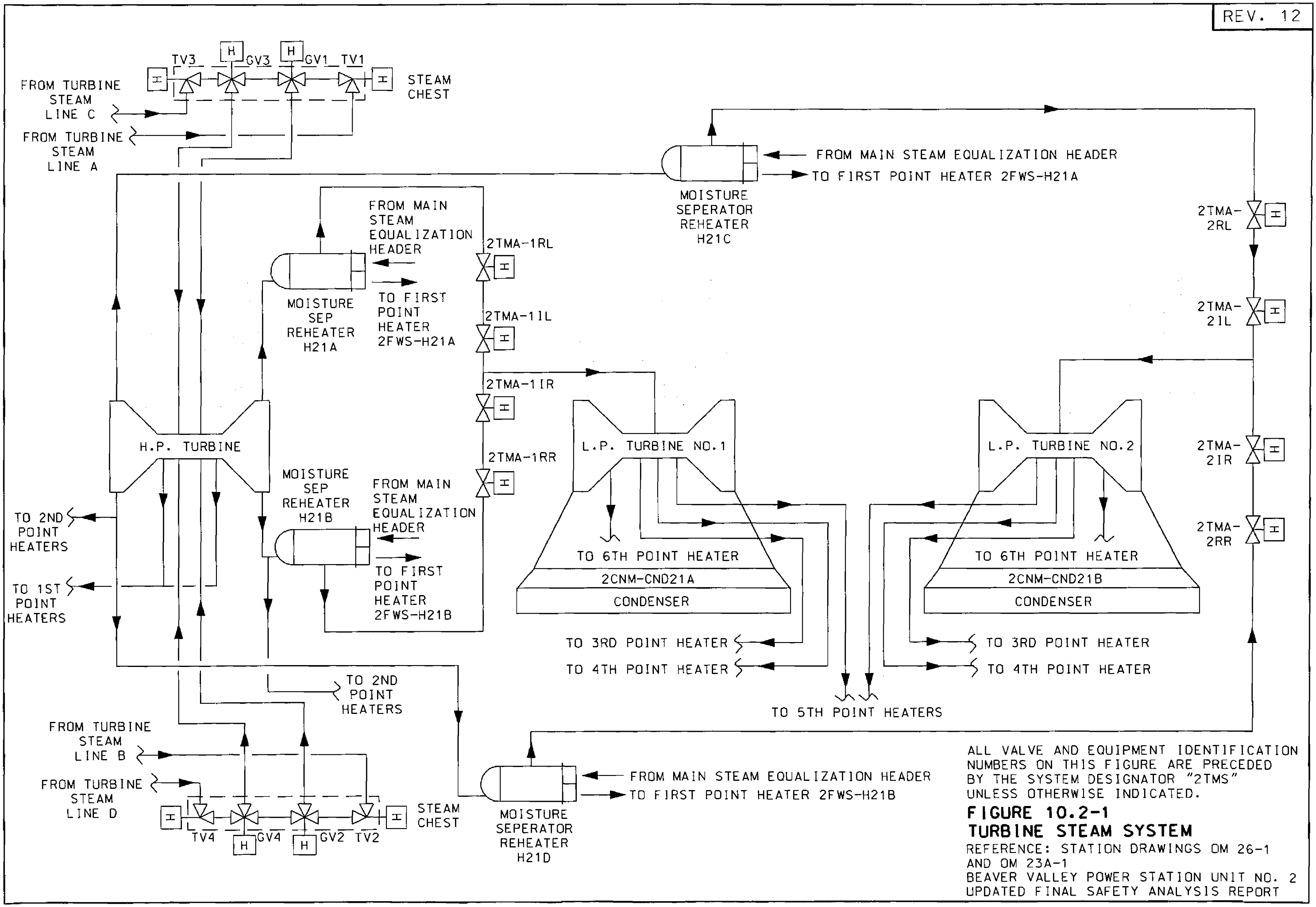
TURBINE TRIP SIGNALS

1. Low turbine bearing oil pressure,
2. Low vacuum in either condenser,
3. Loss of various power supplies to turbine control and protection,
4. Excessive wear (axial movement) of the turbine thrust bearings in either direction,
5. Electrical protection trip (generator),
6. Turbine overspeed trip,
7. Turbine anti-motoring (generator is in motoring mode, turbine is anti-motoring), or
8. External trips:
    a. Reactor trip,
    b. Feedwater isolation,
    c. Manual trip, or
    d. AMSAC.

TABLE 10.2-2

ASTM MATERIAL PROPERTIES FOR SIEMENS
TURBINE ROTORS AND DISCS

Turbine Component	ASTM Spec/CI	0.2% YS (KSI)	UTS (KSI)	Min ELONG (%)	Min RA (%)	Max FATT (°F)	Min CVN Room Temp (ft-lb)
HP Rotor	A470 CI 7	100 min	120-135	18	52	30	40
LP Rotor Shafts	A471 CI 7	100 min	120-135	18	52	30	40
LP Rotor Disks	A471 CI 4	110-130	120 min	17	45	0	45



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2TMS" UNLESS OTHERWISE INDICATED.

FIGURE 10.2-1
TURBINE STEAM SYSTEM

REFERENCE: STATION DRAWINGS OM 26-1 AND OM 23A-1

BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

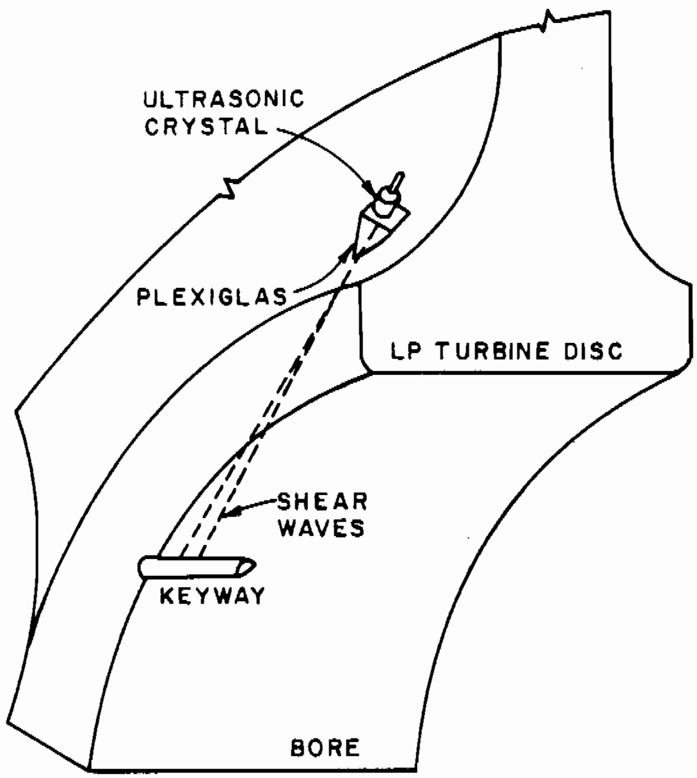


FIGURE 10.2-11
TANGENTIAL AIM INSPECTION TECHNIQUE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

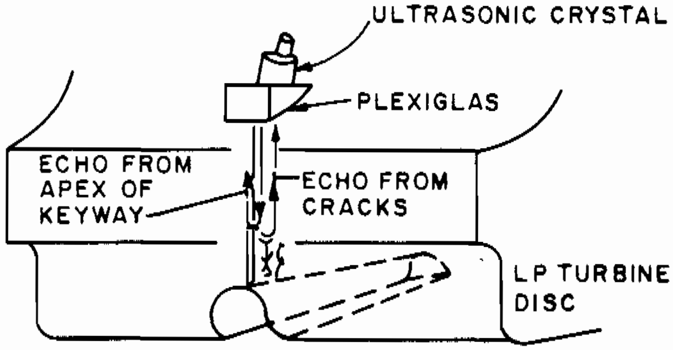


FIGURE 10.2-12
RADIAL AIM
INSPECTION TECHNIQUE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

10.3 MAIN STEAM SUPPLY SYSTEM

The main steam supply system (MSSS) carries steam from the steam generators in the containment to the main turbine in the turbine building and to the auxiliary feed pump turbine in the safeguards area. The system also supplies steam to the auxiliary steam system and turbine gland seal system. The MSSS is shown on Figure 10.3-1.

10.3.1 Design Bases

The MSSS is designed in accordance with the following criteria:

1. General Design Criterion 1, as it relates to the requirement that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

2. General Design Criterion 2, as it relates to safety-related portions of the system being capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods.

3. General Design Criterion 4, as it relates to safety-related portions of the system being capable of withstanding the effects of external missiles and internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks.

4. General Design Criterion 5, as it relates to the capability of shared systems and components important to safety to perform required safety functions.

5. General Design Criterion 34, as it relates to the system function of transferring residual and sensible heat from the reactor coolant system (RCS).

6. General Design Criterion 35, as it relates to the requirement that abundant emergency core cooling be provided such that damage to reactor components is minimal following any loss of reactor coolant.

7. Regulatory Guide 1.29, as it relates to the seismic design classification of the system components.

8. Regulatory Guide 1.115, as it relates to the protection of structures, systems, and components important to safety against the effects of low trajectory turbine missiles.

9. Regulatory Guide 1.117, as it relates to the protection of structures, systems, and components important to safety from the effects of tornado missiles.

10. Branch Technical Position RSB 5-1 (USNRC 1981), as it relates to the design requirements for residual heat removal.

11. NUREG-0138 (USNRC 1976), as it relates to credit being taken for all valves downstream of the main steam isolation valves (MSIVs) to limit blowdown of a second steam generator in the event of a steamline break.

12. The main steam piping from the MSIV to the turbine is designed in accordance with ANSI B31.1. That portion which connects the steam generators and isolation valves is designed in accordance with ASME Boiler and Pressure Code, Section III.

13. The following piping and equipment of the MSSS are designed as Seismic Category I:

    a. Steam generators and supports,

    b. Main steam piping, valves, safety valves, and supports from the steam generators up to and including the first anchor beyond the MSIVs, and

    c. Steam piping from the main steamlines through the residual heat release control valve and the atmospheric steam dump valves to atmosphere, and to the turbine drive for the turbine-driven steam generator auxiliary feedwater pump.

14. The main steam piping supports are analyzed for turbine trip forces as well as seismic criteria. In addition, the system is stress-analyzed for the forces and moments which result from thermal growth and deadweight. The main steam piping within the containment annulus is analyzed for postulated pipe rupture. Sufficient separation, supports, and restraints are provided to prevent damage to the containment liner, adjacent piping, and equipment.

15. The maximum flow through any one main steam safety valve, atmosphere steam dump valve, or residual heat release control valve shall not exceed 890,000 lb/hr at 1,100 psia to limit steam generator blowdown (SGB) if a single valve fails open. The design basis for main steam safety valve sizing is discussed in Section 15.1.4.

The performance requirements of the MSSS are shown on the heat balance diagram, Figure 10.1-1, with the design and performance characteristics shown in Table 10.1-1. The MSSS is designed for 1,100 psia and 560°F, and the environmental design criteria is specified in Section 3.11 for the Class 1E components.

10.3.2 Description

Steam from each of the three steam generators passes through 32-inch outside diameter (OD) carbon steel pipes. A steam flow meter, interconnected with a three-element feedwater control system, is provided in the main steamline at the outlet of each steam generator. A MSIV in each of the three main steamlines is located in the main steam valve house, immediately outside the reactor containment. Following the MSIVs, the three main steamlines enter a single, 38-inch OD manifold. Connections for the turbine steam bypass, turbine steam sealing system, reheater supply, and auxiliary steam supply are provided at the manifold. From this manifold, steam passes to the turbine stop trip valves and governor valves.

The MSIVs automatically prevent reverse flow of steam in case of accidental pressure reduction in any steam generator or its piping. If a steamline breaks between a MSIV and a steam generator, the affected steam generator continues to blow down while the isolation valve prevents blowdown from the other steam generator. In addition, the MSIVs prevent blowdown through a ruptured pipe downstream of the isolation valves. This steamline break accident is discussed in Section 15.1.5.

The wye pattern globe type MSIVs are opened pneumatically and are held open by air pressure. If a pipe ruptures either upstream or downstream of an isolation valve, a main steamline isolation signal causes vent solenoids to release the air, closing the valve by spring force. Maximum closing time for the isolation valve upon receipt of the signal is 6 seconds. Valve closure prevents rapid cooling of the RCS by limiting SGB to a single steam generator. Isolation valve closure also ensures a supply of steam for the turbine-driven steam generator auxiliary feedwater pump.

Five ASME Code Section III safety valves are located in each main steamline outside the containment and upstream of the MSIVs. The combined relieving capacity of these safety valves will prevent maximum secondary system pressure from exceeding 110 percent of the steam generator secondary side design pressure of 1085 psig.

Excess steam generated by the sensible heat in the nuclear steam supply system immediately following loss of load is bypassed directly to the turbine condenser (Section 10.4.1) by means of two turbine steam bypass lines (Section 10.4.4), which provide a total bypass capacity of greater than 40 percent of full load steam flow.

All bypass valves are prevented from opening on loss of condenser vacuum, and excess steam pressure is relieved to the atmosphere through the atmospheric steam 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 from the RCS sensible heat and core decay heat is discharged to the atmosphere through the main steam safety valves. Radioactivity released during this discharge will be negligible since little or no primary coolant leakage is anticipated. However, continuous radioactivity monitoring is provided (Section 11.5) in case of a primary coolant leak to the secondary side through a steam generator. The control of radioactive steam released during such an event is discussed in Chapter 15. A remote electro-hydraulic-operated atmospheric steam dump valve is also provided on each main steam header upstream of the MSIV, outside the containment. These safety grade valves, powered from a Class 1E power supply, will individually modulate to maintain a steamline pressure as determined from the main control room. Individual maximum valve capacity does not exceed 890,000 lb/hr at 1,100 psia, thus limiting SGB if a single valve sticks open.

In addition, a remotely-operated residual heat release control valve capable of releasing the sensible and reactor decay heat to the atmosphere via the residual heat release header is provided. This valve is manually positioned from the main control room. This valve is safety-related and powered from a Class 1E power supply that is redundant to the Class 1E power being supplied to the atmospheric steam dump valves described above. This one valve, which is mounted on the common residual heat release header, serves all three steam generators through connections on each main steamline upstream of the MSIV. 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 a MSIV. In addition, the residual heat release control valve is used to release the steam generated during reactor physics testing and operator training. The maximum capacity of the residual heat release valve does not exceed 890,000 lb/hr at 1,100 psia, thus limiting SGB if the valve sticks open.

Both the atmospheric dump valves and the residual heat release valves discharge to atmosphere through a diffuser for noise suppression. These diffusers do not affect the safety function of the steam dump system.

Radioactive contaminants in the steam generator are monitored by the sampling system connections on the blowdown lines (Section 10.4.8). The operator can minimize secondary system radioactivity concentrations by SGB operation, reduction in power level, and/or isolation of a faulty steam generator.

An off-line post-accident radiation monitor (one detector for each main steam line) is provided to monitor main steam line radioactivity. Section 11.5 includes a description of the monitor design and operation.

Steam is supplied from each main steamline upstream of the isolation valve to the turbine drive for the turbine-driven steam generator auxiliary feedwater pump (Section 10.4.9). The piping is arranged so that any steam generator can supply the turbine drive for this pump. The required steam flow for the turbine drive at rated conditions is 31,000 lb/hr.

Two normally closed, solenoid-operated trip valves are located in series in each steam supply line to the auxiliary feedwater pump. The valves receive a signal to open, as described in Section 10.4.9.5, and are of the fail open type; they are powered from the emergency power supply. Steam pressure is available at the valve inlet at all times. Check valves are provided in each steam supply line to ensure the availability of driving steam in the event of failure of a steam generator or a line break upstream of a MSIV. Indications of operating conditions are available in the main control room. The turbine speed is automatically controlled by the turbine inlet governor valve. The operator adjusts feedwater flow by throttling valves at the pump discharge. Additional description of the steam generator auxiliary feedwater pump operation is contained in Section 10.4.9.

Branch connections from the main steamline between the main steamline trip valves and the turbine stop valves consist of the following:

1. Auxiliary steam supply,
2. Gland steam supply,
3. Reheater steam supply, and
4. Steam bypass (dump) to the condenser.

Each line is provided with shutoff capability and is classified as QA Category II. Additional data on these branch connections are given in Table 10.3-1.

10.3.3 Safety Evaluation

The MSSS is evaluated for environmental and accident conditions, high energy line breaks, and break exclusions in Section 3.6. Also, seismic and safety classifications are discussed in Section 3.2.

The MSIVs are designed to close within 5 seconds and required to close at a maximum of 6 seconds after receipt of a main steamline isolation signal. If a main steamline rupture occurs, a steamline low pressure signal causes the isolation valve in each of the three main steamlines to trip closed. If a rupture occurs downstream of the trip valve, valve closure stops the flow of steam through the pipe rupture, thus checking the sudden and large release of energy in the form of steam, which in turn prevents rapid cooling of the RCS. The MSIV closure also ensures a supply of steam to the turbine-driven auxiliary feed pump.

Single failure of a MSIV is discussed in Section 15.1.5. Further discussion of main steam system component failure can be found in Sections 15.1 and 15.2.

If a main steamline breaks between a MSIV and a steam generator, only that steam generator will blow down. Closure of the MSIV in the ruptured line prevents blowdown from the other steam generators.

The maximum capacity of any single main steam safety valve, steam bypass valve, residual heat release valve or atmospheric dump valve does not exceed 890,000 lb/hr at 1,100 psia inlet pressure. This feature limits the potential uncontrolled blowdown flow rate in the event a valve inadvertently fails or sticks in the open position.

Failure modes and effects analyses (FMEA) to determine if the instrumentation and control and electrical portions meet the single failure criterion, and to demonstrate and verify how the General Design Criteria and IEEE Standard 279-1971 requirements are satisfied, have been performed on the main steamline isolation system. The FMEA methodology is discussed in Section 7.3.2. The results of these analyses can be found in the separate FMEA document (Section 1.7).

10.3.4 Inspection and Testing Requirements

Piping and equipment of the MSSS designed as Seismic Category I require preoperational and periodic in-service testing. For discussion on preoperational tests, refer to Chapter 14. Section 3.9B.6.2 discusses in-service tests of valves. In-service tests of other Class 2 and Class 3 components are discussed in Section 6.6.

Test requirements of the MSIVs in the MSSS are as follows:

Prior to service, each MSIV shall be cycled from fully open to fully closed. This cycling will occur with cold and hot system conditions. During cold system condition tests (i.e., no elevated pressure or temperature), the MSIV trip closure time will be checked. Limit switch operation and indicating lights will also be checked for operability. During hot system condition (no load pressure and temperature), each MSIV will be closed by a trip signal from Train "A," then closed by a trip signal generated from Train "B". For each trip cycle the closure time will be monitored.

10.3.5 Water Chemistry

The secondary side water chemistry is controlled to minimize metal corrosion, scale formation on heat transfer surfaces, and the accumulation of sludge in the steam generator. This is accomplished by continuous injection of chemicals to control pH and oxygen concentration, and the action of the Steam Generator Blowdown System (Section 10.4.8). In addition, the blowdown system flow rate is adjusted to minimize ionic impurities. Turbine plant sampling is described in Section 9.3.2.2. Steam generator blowdown sampling is described in Section 9.3.2.1.

During normal Beaver Valley Power Station - Unit 2 (BVPS-2) operation, the chemical feed system delivers addition chemicals separately to the condensate system by four diaphragm-type, positive displacement feed pumps. Each pump takes suction from separate 415-gallon chemical feed tanks. The injection rate (up to 13.3 gph per pump at 600 psig) is continuously controlled by manual adjustment of the pump stroke from 0 to 100 percent.

Specifications for chemical control procedures are detailed in the BVPS-2 Chemistry Manual. These specifications are based upon EPRI/PWR secondary chemistry guidelines.

For wet lay-up of the secondary side, gross chemical adjustment is accomplished by three positive displacement wet lay-up pumps. The injection rate (up to 40 gph per pump at 1,200 psig) is controlled by adjustment of the pump stroke from 0 to 100 percent. A 415-gallon chemical feed tank provides concentrated chemicals for wet lay-up. Wet lay-up pumps discharge to the primary plant demineralized water storage tank (PPDWST) and the steam generator feedwater inlet.

Chemical spillage and tank overflow are drained to a chemical waste sump.

The radioactive iodine partition coefficients in the steam generator and air ejector are consistent with NUREG-0017 (USNRC 1976). In the steam generator, 5 percent of the iodine leaking from the primary to secondary side is volatile and is treated as a noble gas while the other 95 percent has a partition factor of 0.01. In the air ejector, the partition factor is 0.15 for the volatile 5 percent of the iodine and 0 for the nonvolatile 95 percent of the iodine.

10.3.6 Steam and Feedwater Materials

The typical material specifications used in the Code Class 2 and Class 3 main steam and feedwater piping systems are listed in Table 10.3-2. The materials used for the Code Class 2 portions of the steam generators are discussed in Section 5.4.2.1.

10.3.6.1 Fracture Toughness

Fracture toughness testing of Code Class 2 and Class 3 components was optional in the editions of the ASME Code Section III in effect at the time of procurement for BVPS-2. Due to successful power plant operating experience with the materials of construction, fracture toughness testing was not generally specified for the main steam and feedwater system piping and components. Fracture toughness testing was specified, however, for the weld filler metal used in the field erection of piping. Testing is to the requirements of ASME Code Section III, NB 2400, and the applicable ASME, Code Section II, Part C, filler material specification. In addition, where components were fabricated to later editions of ASME Code Section III that required fracture toughness testing, this testing was performed in accordance with the code then in effect.

10.3.6.2 Material Selection and Fabrication

The pressure retaining materials specified for use in the Code Class 2 and Class 3 main steam and feedwater systems conform to Appendix I of ASMS Code Section III, and to Parts A, B, and C of ASME Code Section II. Compliance to Regulatory Guides 1.31, 1.36, 1.44, 1.50, and 1.85 is discussed in Section 1.8. Welding in areas of limited welder accessibility is controlled, as applicable to the materials of construction, per Regulatory Guide 1.71, as discussed in Section 1.8. Cleaning of Code Class 2 and Class 3 main steam and feedwater systems is controlled in accordance with ANSI N45.2.1, per Regulatory Guide 1.37, as discussed in Section 1.8. Nondestructive examination of tubular products was specified in accordance with ASME Code Section III. The allowable design stresses for tubular products are consistent with the degree of nondestructive testing, as required by ASME Code Section III.

10.3.7 Instrumentation Requirements

Control switches with indicating lights are provided in the main control room for the MSIVs. These valves have an extra set of indicating lights located on the MSIV logic cabinet. These MSIVs require electric power for opening, which is done pneumatically. They will close upon signal actuation by mechanical spring force. These valves are opened manually provided a main steamline isolation signal Train A or Train B is not present. These trip valves will close provided a main steamline isolation signal from either train exists.

Testing capabilities are available at the MSIV logic cabinet for the MSIVs. Pushbuttons are provided on the logic cabinet for performing these test procedures, which consist of partial closing and reopening of these trip valves.

Control switches with indicating lights are provided in the main control room for the main steamline bypass trip valves. These valves are opened manually. The valves will close when they receive a main steamline isolation signal, Train A or Train B.

Annunciation with associated computer inputs is provided in the main control room for the steamline stop valve not fully open and bypass valve not fully closed.

Status indicating lights are provided on the MSIV logic cabinets for emergency trips of channels A and B, solenoid valves open, solenoid valves closed, and both trips available.

Pushbuttons are provided in the main control room for manual initiation of the steamline isolation signal. This signal will be initiated automatically when a high rate of change of steamline pressure (detected in two out of three channels) of any steamline is present and steamline isolation/safety injection is blocked, Hi-2 reactor containment pressure detected in two out of three channels or any steamline pressure low (detected in two out of three channels), either hot or cold leg isolation valve is open, and steamline isolation/safety injection signal is not blocked.

Pushbuttons are provided at the emergency shutdown panel (ESP), which will transfer control to the ESP for the steamline/safety injection block reset. A manual reset pushbutton is used to transfer control back to the main control room.

Annunciation with associated computer inputs is provided in the main control room for: loop A steamline high rate of pressure change for channels II, III, and IV; loop B steamline high rate of pressure change for channels II, III, and IV; loop C steamline high rate of pressure change for channels II, III, and IV; one out of three steamline high rate of pressure change, containment pressure high/high-high for channels II, III, IV; loop A steamline pressure low for channels II, 111, and IV; loop B steamline pressure low for channels II, III, IV; loop C steamline pressure low for Channels II, III, and IV; and steamline pressure low reactor trip and safety injection for loops A, B, and C.

Status indicating lights are provided in the main control room for these functions: steamline pressure high rate of change, one each for Channels II, III, and IV of steamlines A, B, and C; Hi-2 containment pressure, one each for channels II, III and IV; steamline pressure low, one each for channels II, III, and IV of steamlines A, B, and C; and steamline isolation/safety injection blocked, one each for Trains A and B.

Control switches with indicating lights are provided at the chemical feed panel for the hydrazine feed pumps, morpholine feed pumps, and wet layup pumps.

The main steam safety valves (MSSVs) are provided with a Class 1E powered valve position indicator (VPI) system that monitors the positions of the safety valves. The valve position information is provided to two systems: the main steamline monitor (SLM) associated with the digital radiation monitoring system (DRMS) and the plant safety monitoring system (PSMS). The SLM measures steam effluent releases and the PSMS provides safety valve position display in the control room.

10.3.8 References for Section 10.3

U.S. Nuclear Regulatory Commission (USNRC) 1976. Calculations of Releases of Radioactive Material in Gaseous and Liquid Effluents from PWR Reactors. NUREG-0017.

U.S. Nuclear Regulatory Commission 1976. Staff Discussions of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director NRC to NRC Staff. NUREG-0138.

U.S. Nuclear Regulatory Commission 1981. Design Requirements of the Residual Heat Removal System. Branch Technical Position RSB 5-1.

Tables for Section 10.3

Table 10.3-1

MAIN STEAM LINE BRANCH CONNECTIONS

	System Code	Total of Branch Flows (# / hr)	Type Valve	No. of Valves	Size (in)	Opening/ Closure Time (sec)	Design Code	Normal Position
Reheat steam	MSS	787,169	Motor-operated gate	2	10	64	ANSI B31.1	Open
Steam bypass to condenser	MSS	>522,000	Manual gate	2	24	Not applicable	ANSI B31.1	Open
			Pressure control air-operated diaphragm	3	8	3	ANSI B16.10 B16.5 MSS Std. SP-25*	Closed
			Temperature control air-operated diaphragm	15	8	3	ANSI B16.10 B16.5 MSS Std. SP-25*	Closed
Auxiliary steam	ASS	76,000	Manual gate	1	8	Not applicable	ANSI B31.1	Open
			Pressure control air-operated diaphragm	1	8	30	ANSI B31.1	Open
Gland steam	GSS	9,464	Manual gate	1	3	Not applicable	ANSI B31.1	Open
			Motor-operated gate	1	4	20	ANSI B31.1	Open
Steam drain	SDS	12,194	Manual gate	15	1 1/2 to 2	Not applicable	ANSI B31.1	Open

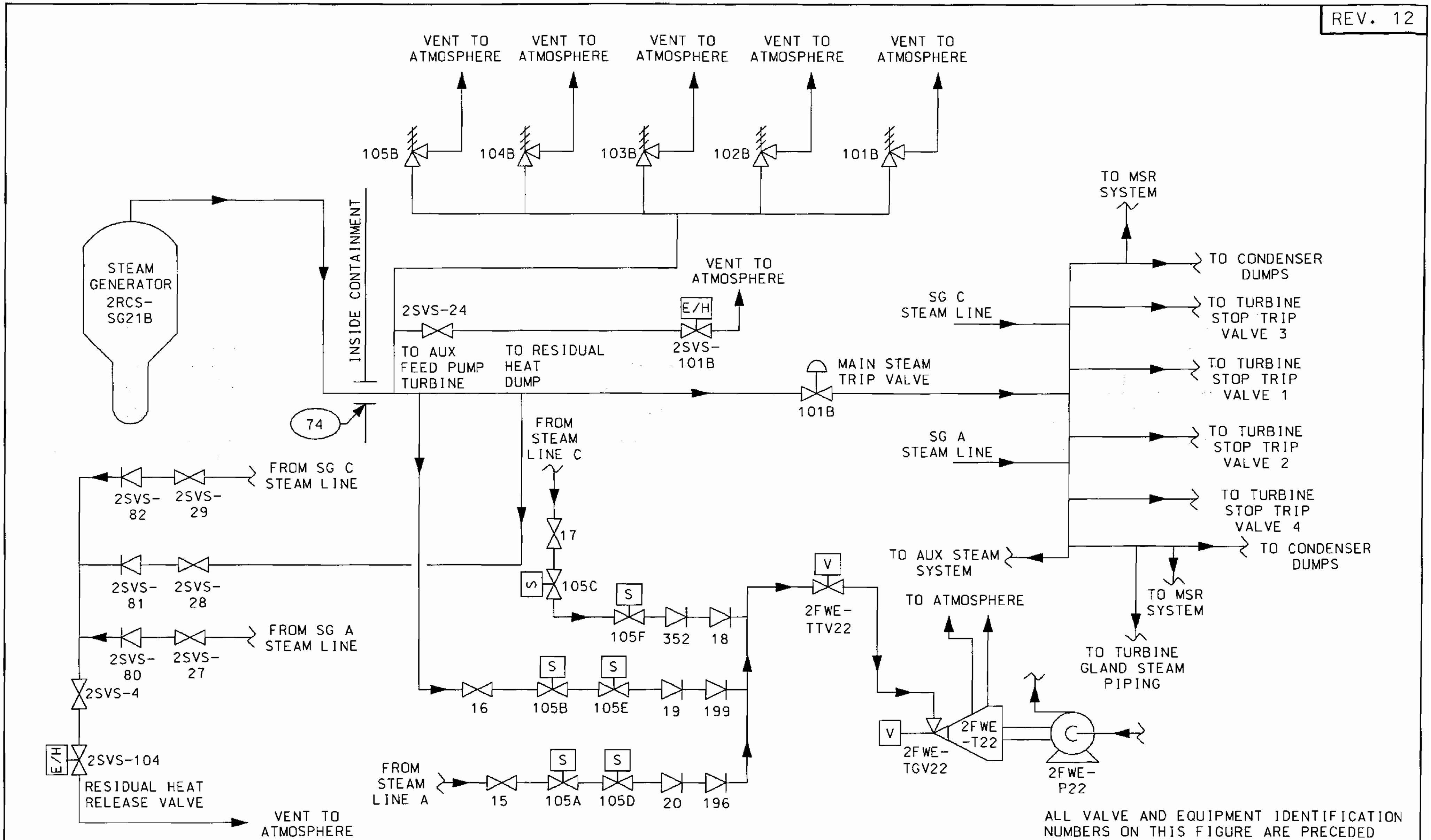
NOTE:

*Manufacturers Standardization Society Standard - Standard Practice.

TABLE 10.3-2

MATERIALS OF CODE CLASS 2 AND CLASS 3
MAIN STEAM AND FEEDWATER PIPING SYSTEMS

Pipes	
Over 24"	SA 155 C1 1 Gr. KC70, or SA 106 Gr.C
Up to 24"	SA 106 Gr.B
Fittings	
Over 24"	SA 234-WPC or WPCW or SA 106 Gr. C
2 1/2" to 24"	SA 234-WPB
Up to 2"	SA 105
Flanges	
All sizes	SA 105
Bolting	
Studs	SA 193 Gr. B7
Nuts	SA 194 Gr. 2H
Valves	
Bodies and Bonnets	SA 105, SA 181 Gr.2, SA 216 Gr. WCB or WCC, SA 350 Gr. LF2, SA 352 Gr. LCB, and SA 479 Type 316
Covers	SA 216 Gr. WCB or SA 516 Gr. 70
Disks and Wedges	SA 216 Gr. WCB
Studs and Bolts	SA 193 Gr. B7
Nuts	SA 194 Gr. 2H



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2MSS" UNLESS OTHERWISE INDICATED.

NOTE: MAIN STEAM LINE "B" IS TYPICAL OF LINES "A" AND "C".

LEGEND

AUX AUXILIARY
SG STEAM GENERATOR
MSR MOISTURE SEPERATOR AND REHEAT

FIGURE 10.3-1
MAIN STEAM SYSTEM

REFERENCE: STATION DRAWINGS OM 21-1 AND OM 21-2

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10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

The main condenser condenses and deaerates steam from the two low-pressure turbine exhausts, the turbine bypass system (TBS) (Section 10.4.4), and miscellaneous drains.

10.4.1.1 Design Bases

The main condenser is designed in accordance with the following criteria:

1. The condenser is non-nuclear safety (NNS) class. The intent of Regulatory Guide 1.26, as addressed in Section 1.8, is met by BVPS-2.

2. To remove 6.286 x 10^9 Btu/hr from the turbine exhaust at 6,713,000 lb/hr steam flow and maintain a 2.99 in Hg abs back pressure with a circulating water inlet temperature of 81°F. Refer to UFSAR Figure 10.1-1 for the operating conditions for the NSSS thermal power of 2910 MWt.

3. To condense and deaerate the turbine exhaust at all loads.

4. To withstand the dynamic and thermal effects of the turbine bypass. The condenser is designed to accept up to approximately 90 percent of the full load steam flow from the TBS.

5. To meet Heat Exchanger Institute, Standards for Steam Surface Condensers, Sixth Edition 1970.

6. To meet the requirements of General Design Criterion 60 as it relates to control of releases of radioactive materials to the environment.

10.4.1.2 System Description

The condenser is a conventional, twin-shell, single-pass, divided water box design, having impingement baffles to protect the tubes where required, with lower casing steam and condensate crossover ducts to equalize pressure, and stainless steel expansion joints between the condenser necks and the turbine exhaust flanges. One sixth point feedwater heater is located in each condenser neck. Partitioned hotwells, with sampling points in each section, are provided to detect inleakage of circulating water (Section 10.4.5). The total hotwell water storage capacity is equivalent to approximately 4 minutes of condensate system flow at full load operation (71,000 gallons).

Condenser cooling water is provided by the circulating water system (CWS). A description of the CWS design, including heat transfer and system flow requirements, is provided in Section 10.4.5.

Table 10.4-1 gives the design parameters and performance characteristics of the main condenser.

10.4.1.3 Safety Evaluation

The condenser is designed for operation at loads up to and including maximum calculated Beaver Valley Power Station - Unit 2 (BVPS-2) output. Tubes in the condenser are fabricated of stainless steel and are protected against impingement of high energy fluids by local baffles and by appropriate distribution piping. Motor-operated butterfly valves are provided at the condenser inlet and outlet water boxes for maintenance isolation (Section 10.4.5.3). The potential for hydrogen buildup in the condenser is negligible. The condenser is designed to maintain a maximum condensate oxygen content of 0.005 ppm with an air inleakage rate of 40 scfm. Noncondensable gases entering the main condenser are removed by the condenser evacuation system (Section 10.4.2).

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 principal radioisotopes extracted from the condenser during leakage conditions are Xe-133, Xe-135, Kr-85, and Kr-88 at the rate of 0.9 Ci/sec, 0.1 Ci/sec, 0.06 Ci/sec, and 0.09 Ci/sec, respectively. These release rates are based on expected primary coolant noble gas concentrations and a 100 lb/day primary to secondary system leak rate.

Radiation monitoring is provided on the discharge side of the air ejectors. Air removal equipment (Section 10.4.2) discharges are routed to the gaseous waste disposal (GWD) system.

Pressure relief diaphragms furnished on the turbine exhaust hood avoid buildup of excessive pressures in the condenser shell.

No safety-related equipment is affected by flooding in the event of a failure of the condenser (Section 10.4.5.3).

The probable circulating water condenser leak rate is expected to be approximately .34 gpm inleakage under normal operation. This is based on one tube in every 2,000 contributing .005 gpm inleakage.

In the event of excessive main condenser leakage, circulating water will enter the condensate system and initiate high conductivity alarms from the sampling analysis performed by the hotwell sample system, a subsystem of the secondary plant sample system (Section 9.3.2).

10.4.1.4 Inspection and Testing Requirements

A total of 12 sample points on the condenser hotwells are used to check the condenser for circulating water inleakage by the secondary plant sample system.

A radiation monitor is installed in the common discharge line of the two air ejectors to detect buildup of noncondensable radioactive gases indicative of steam generator tube leakage.

The condenser shell is hydrostatically tested after installation by completely filling it with water and inspecting for leakage.

Periodic inspection will determine the extent of corrosion, accumulation of debris, scale deposits, and organic growths in the water boxes and tubes. Chlorination of circulating water will reduce organic growths. Preoperational tests are performed on the system as described in Section 14.2.12.

10.4.1.5 Instrumentation Requirements

Level controllers and level alarms on the condenser are discussed under the condensate and feedwater systems (FWS) (Section 10.4.7.5).

The condenser hotwell temperature is monitored by the BVPS-2 computer.

Local indication is provided for the condenser hotwell level, condenser pressure, and the low pressure turbine exhaust hood pressure.

10.4.2 Condenser Evacuation System

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

10.4.2.1 Design Bases

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

1. Heat Exchanger Institute, Standards for Steam Surface Condensers, Sixth Edition 1970.

2. The system is nonsafety-related and is classified as NNS class.

3. General Design Criteria 60 and 64, with respect to provisions for controlling and monitoring the release of radioactivity to the environment.

4. Maintain a 1.0 in Hg abs pressure in the condenser, with air inleakage of 40 scfm during operation, and provide for air removal during start-up.

10.4.2.2 System Description

Two, twin-element, two-stage steam jet air ejector units, each complete with tubed inter- and after-condensers, remove noncondensable gases from the condenser shells. Each element consists of two nozzles (stages) in series. One element of each ejector operating for each condenser shell is sufficient for normal operation. The steam jet air ejectors function by using steam from the auxiliary steam system (Section 10.4.10). The auxiliary steam that condenses in the steam jet air ejector condensers flows through a loop seal to the main condenser (Section 10.4.1).

Each condenser steam jet air ejector is designed to remove 20 cfm of free air when one element is operated with 1,200 lb/hr of steam at 125 psig from the auxiliary steam header, and a minimum of 1,250 gpm of condensate is flowing through the inter- and after-condensers.

For initial condenser shell side air removal, a vacuum priming ejector is provided for each shell. The air removed from the condenser shells by the priming ejectors is discharged to the atmosphere. The BVPS-2 ejector steam (Section 10.4.10) for initial condenser vacuum is supplied from the Beaver Valley Power Station - Unit 1 (BVPS-1) auxiliary steam system or from the auxiliary boilers. When auxiliary steam is being provided by the BVPS-1 auxiliary steam system, radiation monitoring, provided in the BVPS-1 air ejector gaseous discharge piping, indicates potential high auxiliary steam radiation levels. When auxiliary steam is provided by the auxiliary boilers, no radiation monitoring is required.

Auxiliary steam is manually admitted to the priming ejectors prior to BVPS-2 start-up. Operation of the priming ejectors is initiated manually. After establishing a condenser pressure at or below 15 in Hg abs during start-up, the priming ejector is manually shut down and the steam jet air ejector is manually started for holding vacuum. With normal operating vacuum established, only one element on each stage of the steam jet air ejector is required to operate if condenser air inleakage is not excessive. On indication of high absolute pressure in the condenser during normal operation, the second element of each stage of steam air ejector may be manually started.

Two blowers are located on the discharge of the air ejectors. Operation of the blowers or their bypass line is initiated manually when necessary.

The effluent from the air ejectors may contain gaseous radioactivity. These gases are discharged through the process vent atop the BVPS-1 cooling tower via the BVPS-2 GWD system (Section 11.3) and the BVPS-1 GWD system.

During normal system operation the BVPS-2 gases are discharged through a flow path that is located downstream of the radiation monitor that is used to indicate whether the discharge is acceptable. An alarm from this radiation monitor indicates a primary-to-secondary system leak. This flow path has an open valve. A high activity alarm signals the operator to manually close this valve to divert the effluent through the charcoal delay beds to the BVPS-1 cooling tower vent.

Radiation monitors are provided at three separate points in the discharge flow path to detect radioactive gas concentrations. One radiation monitor is located at the discharge of the air ejectors, a second is located in the GWD system downstream of the charcoal delay beds, and the third is located in the effluent line at the cooling tower.

Alarm set points are determined on the basis of maintaining discharges within acceptable limits for environmental releases. Air ejector gaseous discharge is monitored for radiation, upstream of the charcoal delay beds. The air ejector charcoal delay bed exhaust monitor will indicate any adsorption malfunction in the charcoal delay beds for possible operator action. The third monitor located at a final release point on BVPS-1 is for indication of unacceptable environmental releases.

The charcoal delay beds provide sufficient holdup time for the decay of isotopes such as Xe-135, Kr-89, and I-131. For the long-lived noble gases, charcoal beds holdup xenon (the heaviest gas) approximately 8.0 days and krypton approximately 0.45 day. The charcoal bed effluent is continuously monitored by the radiation monitor in the GWD system discharge.

To control moisture in the charcoal delay beds, the gas stream is chilled and dehumidified to 77°F dry bulb and 55°F dew point prior to entering the charcoal beds. Upon excessive primary-to-secondary leakage, which would cause excessive or unacceptable radioactive concentrations in the steam generators or main condenser, operator action may be initiated to terminate the radioactivity release by isolating the faulty steam generator and operating the plant at reduced power.

10.4.2.3 Safety Evaluation

The condenser evacuation system has no safety function and its failure will not affect the safety functions of other equipment. Maintaining vacuum in the condenser is necessary for operation of both the turbine bypass system (TBS) (Section 10.4.4) and the turbine generator (Section 10.2). Failure of the condenser evacuation system will cause a gradual loss of vacuum in the condenser by buildup of noncondensable gases. When the pressure in the condenser reaches approximately 6.0 in Hg abs, or the differential pressure between the twin condenser shells reaches 2.5 in Hg abs, the turbine generator trips.

In the event of a reactor trip and the failure of the TBS to operate because of loss of condenser vacuum, the main steam flow can be discharged by the main steam safety valves and the main steam atmospheric dump valves to the atmosphere. The radiological consequences of these events are discussed in Chapter 15.

The expected activity discharged from the air ejectors is based upon expected primary coolant activity levels combined with a primary-to-secondary side leakage of 100 lb/day (Section 11.3 and Table 11.3-3).

The charcoal delay system will be operated as necessary to minimize the radioactivity released.

10.4.2.4 Inspection and Testing Requirements

Preoperational tests are performed as described in Section 14.2.12.

Normally one of the two first stage ejector elements on the inter-condenser and one of the two second stage elements on the after-condenser are in operation with the others on standby. The operation of these units is observed routinely, eliminating the necessity for testing.

The priming ejectors normally operate only during start-up and need not be tested during BVPS-2 operation.

10.4.2.5 Instrumentation Requirements

Radiation level indicators and recorders are provided in the main control room for the discharges from the air ejectors and for the charcoal delay beds.

A pressure control valve is provided that modulates to reduce the auxiliary steam supply pressure to the proper operating pressure of the air ejector.

Alarms for alert radiation level, high radiation level, and radiation monitor failure are provided in the main control room. A control switch with indicating lights is provided in the control room for the condenser vacuum breaker valve.

Condenser pressures are recorded in the main control room and by the BVPS-2 computer system. An alarm is provided in the control room for low condenser vacuum. Air leakage detection is an intrinsic function of this instrumentation.

10.4.3 Turbine Gland Sealing

The turbine gland sealing system (TGSS), Figure 10.4-1, seals the turbine shaft (rotor) between both the turbine casings and exhaust hoods from the atmosphere, thus preventing leakage of air into the condenser and steam from the turbine into the building. The system is not required to operate under accident conditions.

10.4.3.1 Design Bases

The TGSS is designed in accordance with the following criteria:

1. The system is designed to seal the turbine continuously during start-up and full load operation. The system collects and condenses gland leakoff steam. The system also collects noncondensables.

2. The system is designed to prevent over-pressurization of the gland steam header if the pressure reducing valve fails.

3. The system is nonsafety-related and is designated NNS class.

4. The system provides a backup source of steam for the auxiliary steam system.

10.4.3.2 System Description

The turbine shafts are sealed by glands of the labyrinth type. Steam from the BVPS-1 auxiliary steam system, or auxiliary boiler via the BVPS-2 auxiliary steam system, is supplied at 150 psig to the gland steam header during start-up. When main steam becomes available, the auxiliary steam seal path is isolated and the gland steam header is supplied by the main steam system at 125 psig. In addition, at low loads, steam leakoff from the high pressure turbine control valve is supplied to the gland steam header, and steam leakoff from the high pressure turbine throttle valve is furnished to the high pressure turbine gland supply line.

The steam to the high pressure gland is maintained at 5 psig. Any excess steam is bypassed to the condenser through a spillover valve. The steam to the low pressure turbine glands is maintained at 1 psig. As the high pressure turbine exhaust increases with turbine load, the quantity of steam required to seal the high pressure turbine glands decreases. Also, as the throttle valves are opened, the steam leakoff flow decreases and terminates at full load. Excess steam is bypassed to the condenser.

The leakoff steam from glands and any noncondensables will flow to the gland steam condenser (GSC), where the steam is condensed. The condensed water is then returned to the condenser hotwell. The noncondensable gases are exhausted from the GSC to the environment by one of the two exhaust blowers. The gland seal steam exhaust system is described in Section 9.4.15, which also describes how radioactivity is monitored in the gland seal steam exhaust system.

10.4.3.3 Safety Evaluation

The TGSS has no safety function and its failure will not affect the safety functions of other equipment.

The capability of the gland seal steam exhaust system to handle radioactive leakage for both normal condition and in the event of a malfunction is discussed in Section 9.4.15.

10.4.3.4 Inspection and Testing Requirements

Operation of the gland seal steam exhaust blowers is alternated, thus eliminating the need for periodic testing. Other components of the system are tested and inspected as recommended by the turbine manufacturer. Preoperational tests are performed as described in Section 14.2.12.

10.4.3.5 Instrumentation Requirements

Control switches with indicating lights are provided in the main control room for the gland steam supply control block valve and the gland steam supply control bypass valve.

Pressure indication is provided in the main control room for the gland steam supply header pressure and the high pressure turbine gland supply pressure. These pressures are also monitored by the BVPS-2 computer.

The gland steam supply pressure control valve, the high pressure turbine gland steam pressure control valve, and the low pressure turbine governor end gland steam pressure control valve will modulate to admit steam, when a demand signal is received from their associated controllers.

The high pressure turbine gland steam header spillover valve modulates to remove excessive header pressure, when a demand signal is received from its associated controller.

The GSC differential pressure control valve maintains a constant differential pressure across the condenser by means of a control signal received from its associated controller.

Control switches with indicating lights are provided in the main control room for the manual operation of the gland steam exhausters.

A common turbine gland steam trouble alarm is provided in the main control room for any one of the following conditions: Gland steam header pressure high or low, No. 1 low pressure turbine governor end gland steam pressure high or low, No. 1 low pressure turbine exciter end gland steam pressure high or low, and the gland steam exhauster motor thermal overload. The individual inputs to the main annunciator are also monitored by the BVPS-2 computer.

10.4.4 Turbine Bypass System

The TBS permits a 50 percent external load rejection from full load without reactor or turbine trip. The TBS is shown on Figure 10.4-2.

10.4.4.1 Design Bases

The TBS is designed in accordance with the following criteria:

1. General Design Criterion 4, as it relates to the failure of the TBS due to a pipe break or malfunction should not adversely affect essential systems or components.

2. General Design Criterion 34, as it relates to the ability to use the TBS for shutting down the plant during normal operation.

3. The function of the TBS is to permit a 50 percent external load rejection from full load without causing a reactor or turbine trip.

4. A single turbine bypass control valve sticking open shall not cause an uncontrolled plant cooldown.

5. The TBS piping is designed in accordance with ANSI B31.1, dated 1967, including all addenda through June 30, 1972.

6. The TBS is nonsafety-related and is designated as NNS class.

7. Failure or malfunction of the TBS, including a high energy line break, cannot adversely affect essential systems or components.

10.4.4.2 System Description

On a large external electrical load decrease (up to 85 to 100 percent), the TBS relieves main steam directly to the condenser, thus preventing a reactor or turbine trip and lifting of the main steam safety valves (Section 10.3). The maximum load step change without rod motion is 5 percent.

The load rejection capability; i.e., the capability of the plant to accept a large loss of external load without tripping the turbine, is limited by a turbine trip upon high condenser pressure. Condenser pressure is dependent upon circulating water inlet temperature (CWIT). The higher the CWIT, the higher the final pressure inside the condenser after TBS operation. The maximum CWIT is 90°F. At 90°F the plant has a 50 percent load rejection capability.

Excess steam generated by the sensible heat in the nuclear steam supply system (NSSS), immediately following loss of load, is bypassed directly to the main condenser (Section 10.4.1) 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 some of the valves with steam pressure.

The details of the arrangement of the turbine bypass valves and associated controls are shown on Figure 10.4-2. The bypass valves are 8 inch, carbon steel globe valves with spring and diaphragm air operators. The 18 valves are controlled in 4 blocks, with the valves in each block modulating in parallel. The blocks of valves will open sequentially.

All or several of the bypass valves are opened under the following conditions, provided a turbine condenser vacuum, cooling tower pump, and low-low T_{avg} permissive interlocks are satisfied:

1. On a large step load decrease without reactor trip, the TBS creates a load on the steam generators, thus providing a controlled condensation of generated steam. This enables the NSSS to accept a 50 percent net load rejection from full load without reactor trip. An error signal exceeding a set value of reactor coolant T_{avg} minus T_{ref} fully opens all valves in 3 seconds. T_{avg} is a function of load and is set automatically. The turbine steam bypass valves close automatically as reactor coolant conditions approach their programmed set point for the new load.

2. On a turbine trip with reactor trip, the pressure in each steam generator 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 transient conditions.

3. After a normal orderly shutdown of the turbine generator leading to unit cooldown, the turbine steam bypass valves are used for several hours to release steam generated by the sensible heat. 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 (RHR) system (Section 5.4.7). During start-up, hot standby service, or physics testing, the bypass valves are manually operated from the main control board.

10.4.4.3 Safety Evaluation

The TBS has no safety function and its failure will not affect the safety functions of other equipment because it is located in the turbine building away from all safety-related components.

A potential hazard in the form of an uncontrolled station cooldown caused by a single large valve sticking open is prevented by the use of this group of 18 smaller valves installed in parallel, since any single valve can pass no more than 890,000 lb/hr at main steam system design pressure of 1,100 psia, which is the maximum allowable steam relief valve capacity in Section 4-1 of the Steam Systems Design Manual (Westinghouse Electric Corporation 1978). The effects of a valve sticking open or being opened due to operator error are therefore within Westinghouse design limitations. The steam dump control circuitry prevents inadvertent opening of more than one turbine bypass valve. The analyses performed to determine the design criterion for safety and relief valves is given in Section 15.1.4. The valves will fail closed on loss of power.

Loss of the control air supply to any of the TBS valves prevents the valves from opening or, if the valves are already open, trips them closed. In the event of loss of all control air, the steam generators are protected during all transients by the main steam safety valves.

During start-up, shutdown, operator training, or physics testing, the turbine bypass control valves can be actuated remotely from the main control room.

The turbine bypass control valves are prevented from opening on loss of condenser vacuum, loss of cooling tower pumps, or low-low T_{avg} on two out of three steam generators, and in that case, excess steam pressure is relieved to the atmosphere through the atmospheric dump valves and through the main steam safety valves (Section 10.3).

10.4.4.4 Inspection and Testing Requirements

During the Initial Startup Test Program, the turbine bypass control valves and TBS controls are inspected and tested in accordance with Section 14.2.12.

The TBS piping is inspected and tested in accordance with Paragraphs 136 and 137 of ANSI B31.1.

10.4.4.5 Instrumentation Requirements

A steam dump control mode selector switch and redundant interlock selector switches are provided in the main control room. Loss of condenser vacuum and circulating water pump interlocks are provided for the turbine bypass control valves.

The following control switches are provided in the main control room for operation of the TBS: steam bypass control mode selector switch (reset-T_{avg} -steam pressure), steam bypass interlock selector switches (off/reset-on-defeat T_{avg}), and selector switches (loop 21 T_{avg} defeated, loop 22 T_{avg} defeated, loop 23 T_{avg} defeated).

Manual/Auto stations for the atmospheric steam dump valves are provided in the main control room and at the emergency shutdown panel (ESP). A pushbutton at the ESP will transfer control from the main control room to the ESP. A manual reset at the relay will transfer control from the ESP back to the main control room. If their respective steam line pressures are not high, the atmospheric steam dump valves can be modulated automatically or manually from either the main control room or from the ESP.

Manual stations for two of the atmospheric steam dump valves are provided at the alternate shutdown panel (ASP). A pushbutton on the ASP will transfer control from the main control room or the ESP to the ASP. A manual reset at the relay on the ASP will transfer control back to either the main control room or to the ESP. The atmospheric steam dump valves can be modulated manually from the ASP provided the transfer pushbutton on the ASP has been depressed.

Annunciation is provided in the main control room when control is at the ESP or at the ASP. These conditions are also monitored by the BVPS-2 computer. Red (open) and green (closed) indicating lights are provided at the main control board, at the ESP, and at the ASP to indicate where the control is at.

A manual loading station for the atmospheric residual heat release valve is provided in the main control room and at the ESP. A pushbutton at the ESP will transfer control from the main control room to the ESP, and a manual reset at the relay on the ESP will transfer control from the ESP back to the main control room. The atmospheric residual heat release valve can be modulated manually from either the main control room or from the ESP.

Annunciation is provided in the main control room when control is at the ESP. This condition is monitored by the BVPS-2 computer, and red (open) and green (closed) indicating lights are provided at the main control board and at the ESP to indicate where the control is at.

Annunciation is provided in the main control room for steamline pressure high, which is a common annunciator with individual computer points for all main steamlines, and steam dump system loss of control power, which is also monitored by the BVPS-2 computer. The following inputs are monitored by the BVPS-2 computer: small load rejection, large load rejection, main steam header pressure, condenser available, steam dump actuation, one for each steam dump valve bank trip open signal, reactor coolant loop 21 T_{avg}, reactor coolant loop 22 T_{avg}, reactor coolant loop 23 T_{avg}, and reactor coolant loops median T_{avg}.

Status lights are provided in the main control room to monitor the following conditions: small load rejection, large load rejection, steam dump actuation, condenser unavailable, Train A two out of three reactor coolant loops low-low T_{avg}, T_{avg} interlock defeated, Train B two out of three reactor coolant loops low-low T_{avg}, one for each steam dump valve open and closed, and one for each steam dump valve bank trip open signal. Indicators are provided in the main control room to monitor the following conditions: loop 21 main steam line pressure post-accident monitoring (PAM) 2, loop 22 main steam line pressure PAM 2, loop 23 main steamline pressure PAM 2, loop 21 main steamline pressure, loop 22 main steamline pressure, loop 23 main steamline pressure, steam dump - median T_{avg}, reactor coolant loop 21 T_{avg}, reactor coolant loop 22 T_{avg}, reactor coolant loop 23 T_{avg}.

A temperature recorder is provided in the main control room for median T_{avg} for loops 21, 22, and 23.

Automatic signals for opening the bypass control valves are discussed in detail in Section 7.7.

10.4.5 Circulating Water System

The CWS provides cooling water for the main condenser (Section 10.4.1) of the turbine generator unit (Figure 10.4-3). It is a closed-loop system consisting of cooling tower pumps, a pumphouse, circulating water and blowdown piping, main condenser vacuum priming system, mechanical tube cleaning system, and a natural draft cooling tower. Makeup water is supplied to the closed-loop CWS by discharging the plant service water into the circulating water condenser discharge lines.

10.4.5.1 Design Basis

The CWS is nonsafety-related and is classified NNS class.

The CWS is a moderate energy piping system and is not protected against the dynamic effects of a postulated pipe rupture; however, protection is inherent in the design, since the majority of the circulating water piping is buried.

The CWS complies with General Design Criterion 4, as it relates to design provisions provided to accommodate the effects of discharging water that may result from a failure of a component or piping in the CWS.

10.4.5.2 System Description

The CWS consists of cooling tower pumps, a pumphouse, circulating water piping, main condenser vacuum priming system, mechanical tube cleaning system, natural draft cooling tower, and associated hydraulic and electrical equipment. The system flow diagram is shown on Figure 10.4-3.

The CWS contains four cooling tower pumps that are located in a pumphouse between the turbine building and the cooling tower. The pumphouse arrangement satisfies the net positive suction head requirements of the pumps. Four 25 percent capacity pumps are provided to deliver the circulating water flow to the cooling tower. Each pump is rated as shown in Table 10.4-2.

The natural draft cooling tower is a hyperbolic shell counter-flow tower equipped with an impingement-type drift eliminator system, an icing control system, a system to zone 40 percent of the tower fill, and two bypass gates, each capable of bypassing approximately half of the circulating water flow directly to the cooling tower basin. The icing control system consists of a perforated pipe ring at the circumference of the cooling tower fill on the interior of the shell, which is serviced by a system of ten 18-inch motor-operated butterfly valves and associated piping that connect the ring to the ends of the hot water distribution flumes. The ring allows for a veil of hot water to shield the air inlet, warming the incoming cold air. It also serves to reduce the total air flow, which results in minimizing the possibilities for ice accumulation on the fill. The zoning system consists of a system of dividers and end walls in the distribution flumes that allow water to be bypassed under the distribution pipes serving the central 40 percent of the fill. Flow to the flumes is controlled by power-operated gates installed in the tower risers. The zoning system allows cooling water to be concentrated onto a smaller fill area, thus reducing cooling tower icing potential.

Cooling tower design parameters are presented in Table 10.4-3.

Circulating water flows by gravity from the basin of the cooling tower through fixed panel screens and then to the inlet water boxes of the condenser. The condenser is described in Section 10.4.1. The water passes through the tubes of the condenser to the outlet water box.

The condenser operates as a siphon, with prime maintained by a vacuum priming system. The circulating water then flows to the pumphouse outside the turbine building. The discharge lines of the SWS tie into the CWS between the condenser outlet water boxes and the pumphouse. The four cooling tower pumps, mounted in the pumphouse, pump the water to the top of the cooling tower fill where it is discharged into the cooling tower distribution system. The cooling tower blowdown is discharged from the circulating water discharge flume through a 36-inch butterfly valve located near the bottom of the discharge flume. Discharge flow rate is controlled by an overflow weir which divides the blowdown discharge chamber adjacent to the flume. This weir controls water level in the cooling tower basin and blowdown discharge rate. Blowdown is conveyed by the blowdown discharge system to the Ohio River. The blowdown line can also be used to drain the cooling tower basin through a normally closed 24-inch butterfly valve.

Blowdown from the circulating water of BVPS-2 is combined with the blowdown discharge from BVPS-1 at the outfall structure and is discharged into the Ohio River.

The estimated chemical composition of the circulating water as of initial BVPS-licensing is presented in Table 10.4-4. This Table is therefore considered historical. Chemical constituents will be concentrated in the CWS by as much as 2.4 times the concentrations in the makeup water. Biofouling control will be achieved by chemical addition. Corrosion will be monitored to ensure that the design requirements of system components are maintained.

The CWS system is treated with dispersant, surfactant and halogens for biofouling control at the cooling tower basin. The makeup water to the cooling tower (service water) is treated with dispersant, corrosion inhibitor and halogens as required during the year for biofouling control and corrosion control. The chemical addition system is designed to maintain a residual halogen concentration at the condenser outlet while not exceeding administrative limits for discharge to the river. The system is designed with sample capability to monitor for chemical additive concentrations. This treated water will control biofouling of the condenser tubes and minimize it in the balance of the CWS.

A vacuum priming system is provided to prevent air binding in the condenser waterboxes and sections of the circulating water piping. The system consists of two full-size vacuum pumps, a vacuum priming tank, air separating tanks, and associated piping and controls. One vacuum pump is normally running with the other pump on standby. Air dissolved in the circulating water, which is released at high points in the system, that operates below atmospheric pressure, is continuously drawn off by the vacuum priming system to maintain a siphon to the cooling tower pump suction.

A mechanical tube cleaning system is provided to maintain the condenser performance. The system (Amertap) continuously circulates sponge rubber balls through the condenser tubes. The balls are slightly oversized and provide a wiping action which prevents the buildup of deposits on the tube walls. System components consist of ball distributors, strainer sections to recover balls, recirculating systems for reinjecting balls into the circulating water inlet lines, collectors for removing balls from the cleaning system, and various valves and control equipment.

10.4.5.3 Safety Evaluation

The CWS is a nonsafety-related system and is independent of the emergency cooling requirements. During normal cooldown, service water will be discharged to the CWS and allowed to discharge to the river through the cooling tower blowdown system. The CWS is not needed to cool this water. The emergency service water discharge system, which is independent of the CWS, will be used for emergency discharge of service water (Section 9.2.5).

The hyperbolic shape of the cooling tower is inherently strong and stable. The only credible collapse would be a postulated failure of the shell support columns. Such a collapse mechanism could be described as overturning about the heel of the tower, that is, rotation of a point diametrically opposite the shell support columns.

Since the diameter of the tower at its base is nearly equal to the total height, this postulated collapse would not affect areas greater than about one-half a tower base diameter away from the supporting columns. All Category I structures for both BVPS-1 and BVPS-2 are outside the affected area.

The CWS is physically isolated and remote from both the ultimate heat sink (Section 9.2.5) and the safety-related portions of the SWS (Section 9.2.1) so that a failure in the CWS will not render any parts of safety-related portions of the SWS inoperable.

The interface between SWS and CWS are the two points where the service water discharges into the circulating water lines just downstream of the condenser. The SWS is also provided with its own separate emergency discharge system, which discharges directly into the Ohio River, so that the blockage of these two points will not prevent service water discharge.

Cooling tower pumps could continue to run during an accident unless offsite power is lost or the operator manually trips the pumps. The CWS is not used for cooling safety-related equipment.

Expansion joints are located at the suction and discharge of each pump. A rupture of an expansion joint in the pumphouse will discharge water inside of the pumphouse at the operating floor level that would initially fill the valve pits on the suction side of the pumps. Flood indicators are installed in these valve pits to provide flood alarm to the main control room. The BVPS-2 pumphouse is located more than 300 feet from the nearest safety-related structure.

Because of this separation, the site grading, and the storm drainage systems, no safety-related equipment would be affected.

Expansion joints are also located in the turbine building between the water boxes and the motor-operated butterfly valves on both the inlet and the outlet sides of the condenser and downstream of the strainers in the condenser discharge line. If a rupture should occur in an expansion joint in the turbine building, the escaping water would accumulate in the retention pit around the condenser and in the valve pits on the discharge side of the condenser. Flood indicators are installed below floor level (el 730 feet-6 inches) on both the inlet and outlet sides of the condenser and in the retention pit. These flood indicators will provide flood alarm to the main control room. Upon alarm, the operator will identify and isolate the failed joint to minimize the effects of flooding on the turbine building equipment. Operator action is not required to protect safety-related equipment.

There are no structures, systems, or components credited in accident analyses or required to be safety related (as listed in UFSAR Table 3.2-1) in the turbine building, although some equipment may have been procured to that standard or evaluated as such. Passageways from the turbine building enter the auxiliary building and the service building at el 735 feet-6 inches, which is 5 feet above the turbine building floor. Piping penetrations into safety-related areas below this level are encased in concrete and are therefore water-tight. The maximum flow through a ruptured expansion joint would be about 170,000 gpm. The turbine building side panels will release and discharge the water into the yard area before the water level could reach el 735 feet-6 inches. Circulating water discharged into the yard area of the turbine building will flow away from safety-related areas, along the railroad bed leading away from the southeast corner of the turbine building towards Peggs Run.

In summary, there are no safety-related structures, systems, or components that will be submerged following failure of a rubber expansion joint in the turbine building (Section 3.4.1).

10.4.5.4 Inspection and Testing Requirements

The circulating water pumps and motor-operated valves (MOVs) will be functionally tested during start-up (Section 14.2.12). The CWS is in continued use and does not require periodic testing. Standby equipment will be cycled into service occasionally to ensure their availability.

10.4.5.5 Instrumentation Requirements

Control switches with indicating lights for the cooling tower pumps are provided in the main control room. The cooling tower pumps are manually operated and are interlocked with their respective suction and discharge valves for proper pump operation. An amber light is provided in the main control room to indicate to the operator the proper time intervals for the manual stopping of more than one cooling tower pump. Ammeters are provided in the main control room for each cooling tower pump. The BVPS-2 computer monitors the starts and stops of each pump.

The discharge valves of the cooling tower pump open automatically when a manual demand start signal for the associated pump is initiated, and closes when the cooling tower pump is stopped. Valve position indicating lights are provided in the main control room. Control switches with indicating lights are provided in the main control room for manual operation of the cooling tower pumps suction valves.

Indicating lights are provided in the main control room for each condenser outlet valve. Indicating lights for the inlet and outlet valves are also provided locally. The operation of the valves is local manual. Self supplied cooling water, from the discharge of the cooling tower pumps, is the method of providing cooling for the pump and motor bearings.

Control switches, and indicating lights are provided in the main control room for the cooling tower deicing valves, cooling tower bypass sluice gate valves, and the zoning slide gate valves. (Functions of these valves are described in Section 10.4.5.) These valves are manually operated.

A common annunciator is provided in the main control room with the following inputs: cooling tower pumps trip, cooling tower pump stopped and respective discharge valve not closed, seal injection pump trip, cooling tower pumps discharge pressure high and cooling tower pump house floor level (water) high. The preceding conditions are monitored by the BVPS-2 computer. Annunciation is also provided for the condenser inlet and outlet valves retention pits levels high and condenser differential pressure, and these conditions are monitored by the BVPS-2 computer. Computer monitoring is also provided for the following: cooling tower blowdown flow, condenser differential pressure, condenser water boxes inlet temperature, cooling tower pump starts and stops and condenser water boxes outlet temperatures.

Indicators are provided in the main control room for cooling tower pumps discharge temperatures and condenser water boxes inlet temperatures. A recorder and totalizing indicator are provided in the main control room for cooling tower blowdown flow.

A common selector switch with indicating lights is provided for the vacuum priming pumps. The selector switch has the capability of selecting a lead/follow arrangement for either pump. One pump runs continuously while the other is in standby, and the standby pump will start automatically when the lead pump stops or there is low vacuum in the vacuum priming tank. Cooling water admission valves for the vacuum priming equipment seal water heat exchangers operate automatically, depending on the starting and stopping of their respective vacuum priming pump. Selector switches are provided locally for the vacuum priming recirculation pumps. These pumps can be run manually or automatically. On automatic, these pumps will start and stop whenever their respective vacuum priming pump is running.

The condenser water boxes and condenser discharge lines air separating tanks water levels are automatically maintained by their respective level controllers and level control valves.

The mechanical tube cleaning system is an Amertap Corporation tube cleaning system. The system controls are located local to the condensers. The system can be operated in the manual or automatic mode from the local control panel. Annunciation is provided at this panel for monitoring of the system parameters. Indicating lights are provided on the local panel for system pumps, valves, and collection screens operation.

Refer to Section 9.2.1.1 for additional references to chlorination system control and monitoring functions.

10.4.6 Condensate Cleanup System

The CCS consists of the condensate polishing system (CPS) and the powdered resin dewatering system (PRDS).

These systems have been retired in place and are no longer connected to the Condensate System. Cleanup of the condensate is accomplished by the Steam Generator Blowdown System.

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10.4.7 Condensate and Feedwater Systems

The condensate and feedwater systems return condensed steam from the condenser (Section 10.4.1) and the drains from the regenerative feedwater heating cycle to the steam generators, while maintaining the water inventories constant throughout the systems. The systems automatically control the water levels in the steam generators and condenser hotwells during steady state and transient conditions.

A simplified schematic of the condensate system is shown on Figure 10.4-12. A simplified schematic of the feedwater system is shown on Figure 10.4-14.

10.4.7.1 Design Bases

The FWS and the condensate system are designed in accordance with the following criteria:

1. Regulatory Guides 1.26 and 1.29, as they relate to the quality group and seismic design classification of safety-related components:

   a. The portion of the FWS extending from and including the feedwater isolation valves nearest the containment to the steam generator inlets and feedwater control valves are safety-related, QA Category I, Seismic Category I, and are designed in accordance with ASME Section III, Code Class 2, and are designated Safety Class 2.

   b. The entire condensate system and the remainder of the FWS upstream of the feedwater isolation valves are neither safety-related nor Seismic Category I; are designed in accordance with ANSI-B31.1 dated 1967, including all addenda through June 30, 1972; and are designated NNS class. Portions of the feedwater piping which are in QA Category I buildings are seismically designed.

   c. The high pressure and low pressure feedwater heaters are designed in accordance with ASME Section VIII.

2. The condensate system and the nonsafety-related portions of the FWS are automatically isolated from the steam generators within 5 seconds following a feedwater isolation signal (Section 7.3).

   The feedwater isolation valves nearest the containment are located as close as practicable to the containment structure. The feedwater control valves serve as the secondary feedwater isolation valves. Feedwater bypass control valves are normally closed.

3. Branch Technical Positions ASB 3-1 and MEB 3-1 (USNRC 1981), as they relate to breaks in high and moderate energy piping systems outside containment and as described in Section 3.6.

4. General Design Criterion 2, Regulatory Guides 1.29, 1.102, and 1.117, as they relate to structures housing the safety-related portion of the FWS being capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods.

5. General Design Criterion 4, as it relates to structures housing the safety-related portion of the FWS being capable of withstanding the effects of external missiles and internally-generated missiles, pipe whip, and jet impingement forces associated with pipe breaks, and Branch Technical Position ASB 10-2 (USNRC 1981), as it relates to the dynamic effects associated with possible hydraulic instabilities. Piping supports and restraints are designed to withstand the effects of water hammer, which are postulated in all parts of the FWS, from the discharge of the feedpumps to the inlet of the steam generators.

6. General Design Criterion 5, as it relates to the capability of shared systems and components important to safety to perform required safety functions. There are no shared safety-related portions of the condensate system and the FWS.

7. General Design Criterion 44, as it relates to redundancy of components so that, under accident conditions, the safety-related portions of the FWS can be isolated assuming a single active component failure, and as it relates to the capability of the system to transfer heat loads from the steam generators under both normal and accident conditions.

8. General Design Criterion 45, as it relates to design provisions to permit periodic in-service inspection (ISI) of system components and equipment.

9. General Design Criterion 46, as it relates to design provisions to permit appropriate functional testing of the system and components to assure structural integrity, leaktightness, operability and performance of active components, and the capability of the integrated systems to function as intended.

10.4.7.2 System Description

Principal operating characteristics of the condensate system and the FWS are shown on Figure 10.1-1 and in Table 10.1-1. Principle components are shown on Figures 10.4-12 and 10.4-14. The condensate is normally drawn from the condenser hotwell by two of the three half-capacity, motor-driven, vertical condensate pumps. The pumps discharge into a common header which passes the condensate through the steam jet air ejector condensers, and the turbine gland steam condenser. Downstream of the gland steam condenser, condensate passes through two parallel flow paths of low pressure feedwater heating (fifth point heater drain coolers and feedwater heaters, Numbers 2 through 6). The two flow paths are combined to ensure mixing and pressure equalization upstream of the feedwater pumps. The feedwater/condensate passing through the feedwater heaters is heated by extraction steam taken from the turbine (Section 10.4.11). The spare condensate pump will auto-start on loss of one of the normally running condensate pumps and/or low condensate header discharge pressure.

The condenser hotwell is designed to operate at normal level, such that a volume equivalent to approximately 4 minutes of condensate flow (71,000 gallons) is available to the condensate pumps. The water level is automatically maintained by a 200,000 gallon secondary plant demineralized water storage tank (SPDWST) (Section 9.2.6), which provides storage of makeup condensate and accommodates surges within the turbine plant cycle. Makeup flow to the hotwell is gravity-fed from the SPDWST. Hotwell drawoff is accomplished by diverting water from the condensate header to the SPDWST. Each of the three vertical, barrel-type, condensate pumps is rated at 9,700 gpm at 1,078 feet total discharge head (TDH).

Two half-size, motor-driven steam generator feedwater pumps, each rated at 15,200 gpm and 1,694 feet TDH, are furnished to supply feedwater to the three steam generators. A motor-driven start-up feedwater pump is provided to minimize operation of main feedwater pumps at low flow during start-up and low load operation. The start-up feedwater pump can be operated in parallel with one steam generator feedwater pump if the other feedwater pump is out of service.

The steam generator feedwater pumps discharge through two half-size, high pressure feedwater heaters (first point heaters), arranged in parallel, to a common discharge header for distribution to the steam generators. Feedwater flows to each steam generator through individual feedwater flow control valves. Each valve is positioned by a three-element feedwater control system. A manual bypass around each first-point heater allows isolation of these heaters for maintenance without a unit shutdown. To provide better controllability during start-up and shutdown, a small bypass valve around each feedwater control valve provides automatic control of feedwater flow. The bypass valve is used when the feedwater flow is less than 15 percent of design flow.

Malfunction of any low pressure feedwater heater necessitates isolation of that entire string of low pressure heaters in which the malfunctioning feedwater heater is located. Isolation valves are provided for each flow path of low pressure feedwater heaters and each high pressure feedwater heater. In case of malfunction of any of the feedwater heaters, the isolation valves are closed. The turbine generator load must be reduced when a string of heaters is out of service.

A bypass exists around the sixth point heaters which can be aligned using control switches in the main control room. Since there are no valves in the extraction steamline between the turbine and the sixth point heater, the bypass prevents turbine water induction.

Upon a 50 percent-or-greater load rejection, a low pressure feedwater heater bypass valve automatically opens. Condensate flows directly to the feedwater pump suction header, bypassing the sixth through second point heaters. This enables the condensate pumps to supply adequate flow to the feedwater pumps when the flow from the heater drain pumps is lost during transient conditions resulting from load rejections.

Drains from the reheater section of the four moisture separator/reheater units, provided with the turbine generator, flow to four reheater drain receivers. Two reheater drain receivers drain to each of the two first point heaters. Drains from the separator section of the moisture separator/reheater units flow to four separator drain receivers. Drains from the four separator drain receivers, two first point heaters, and two second point heaters, flow to two second point heater drain receivers. From the second point heater drain receivers, the drains are pumped to the suction of the feedwater pumps utilizing the heater drain pumps and/or the separator drain pumps. One heater drain pump and/or one separator drain pump take suction from one second point heater drain receiver as needed to support plant load conditions.

Chemical feed equipment is provided to ensure proper chemistry control. This equipment is discussed in Section 10.3.5.

10.4.7.3 Safety Evaluation

The main FWS 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). Redundant valves are provided for this function. The feedwater isolation valves are located in the main steam valve area with Seismic Category I supports and are designed to function with the environmental effects of a nonmechanistic pipe rupture. Valve closure time is described in Table 6.2-60. The feedwater control valves and bypass control valves, located in the service building, are located in NNS class lines. The feedwater control valve’s closure time plus the ESF signal will be ≤7 seconds. These lines and their supports are designed for seismic loads. Failure of these lines will not prevent feedwater isolation.

2. The Safety Class 2 piping of the main FWS 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 Safety Class 2 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 ability of the feedwater system to perform its safety function is assured by conformance to the design criteria listed in Section 10.4.7.1.

A loss of normal feedwater flow results in a reduced capability for steam generator heat removal. Such a loss could result from a pipe break, pump failure, valve malfunction, or a loss of normal ac power. In the event of such an occurrence, the AFWS ensures a sufficient supply of cooling water for safe shutdown (Section 10.4.9).

The effects of the condensate system and the FWS equipment malfunctions on the reactor coolant system (RCS) are described in Sections 15.2.7 and 15.2.8.

The following features have been provided to reduce the possibility of water hammer in the FWS:

1. The steam generator feed ring is provided with J-tubes to prevent drainage of water during low steam generator water level (Section 5.4.2).

2. The feedwater piping connections of the steam generators are made with an elbow arrangement which does not present a horizontal pipe run immediately upstream of the feedwater nozzles. This configuration should prevent formation of steam pockets under low steam generator water level conditions.

Release of radioactivity to the environment in the event of pipe rupture in the condensate or FWS will not exceed releases that would occur from a pipe rupture in the main steam system (Section 15.1.5).

Breaks in system piping will not result in adverse effects on the functional performance of essential systems or components (Section 3.6). Components in the main steam valve area are designed for the effects of a nonmechanistic pipe rupture.

10.4.7.4 Inspection and Testing Requirements

Piping in the condensate system and the FWS will be hydrostatically tested during construction. All active system components such as pumps, valves, and controls will be functionally tested during start-up (Section 4.2.12). Design provisions for periodic testing are addressed in Sections 7.1.2.4 and 7.3.2.2.5.

In-service inspection, as required by ASME Section XI for the Safety Class 2 portions of these systems, are discussed in Section 6.6.

Samples are taken from the condenser hotwell, the discharge of the condensate pumps, and the discharge of the steam generator feedpumps. The sampling systems determine oxygen content, pH value, and conductivity (ion content). The sampling systems are discussed in detail in Section 9.3.2.

Preoperational tests are performed as described in Section 14.2.12.

10.4.7.5 Instrumentation Requirements

Control switches with indicating lights are provided in the main control room for the condensate pumps. During normal plant operation, two condensate pumps are running. The third pump is automatically started if one of the operating pumps trips or if the condensate discharge header pressure is low.

Condensate discharge header pressure indication is provided on the main board in the main control room. Annunciation is provided in the main control room for condensate pump auto-start/stop and condensate pump suction strainer differential pressure high. These are also monitored by the BVPS-2 computer system.

Minimum condensate flow is controlled by flow control valve in a recirculation line to the main condenser. Indicating lights for valve position are provided on the main board in the main control room.

The hotwell level of the condensers is automatically controlled. Hotwell level indication and annunciation for hotwell high and low levels are provided in the main control room.

The SPDWST is filled from the demineralizer make-up system when there is low level indication, which actuates the fill line level control valve.

Annunciation is provided in the main control room for low and high levels in the SPDWST. The SPDWST level is indicated in the main control room. These are also monitored by the BVPS-2 computer system.

Control switches with indicating lights are provided in the main control room for the main and start-up feedwater pumps. The feedwater pumps are manually operated. A minimum recirculation flow control valve and a feed pump discharge valve are provided for each feedwater pump. The recirculation valve will open or close, as required, depending on the operation of the feedwater pumps.

The steam generator feedwater control system establishes and maintains the feedwater level in each steam generator within limits by positioning the feedwater control valve in the feedwater line to each steam generator. The feedwater control valve responds to a three-element feedwater regulator. Input signals are feedwater flow, main steam flow, and steam generator water level. During power operation below approximately 15 percent load, each main feedwater control valve is bypassed by a smaller flow control valve. The bypass flow control valve responds to a single element feedwater regulator. The bypass valve is controlled by steam generator water level.

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 test 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 must also be reset by a pushbutton switch in the main control room after the isolation signal is removed.

Annunciation is provided in the main control room for steam generator feedwater pump auto-stop, start up feedwater pump auto-stop, steam generator feedwater pump discharge equalizing header pressure low, steam generator feedwater pump recirculation valve open, steam generator feedwater pumps 21A, B/auxiliary lube oil pump trouble, startup feedwater pump 24/auxiliary lube oil pump trouble, feedwater isolation trip valves nitrogen pressure low, and steam generator feedwater pump suction pressure low. These conditions are also monitored by the BVPS-2 computer system.

Ammeters are provided in the main control room to each main and start-up feedwater pump motor.

Main feedwater pump discharge header pressure indicators are provided in the main control room.

Indication is provided in the main control room for feedwater to steam generator flow, steam generator steam pressure, turbine first stage pressure, and steam generator water level. These conditions are also monitored by the BVPS-2 computer system. Indication is provided on the alternate shutdown panel (ASP) for steam generator steam pressure and steam generator water level (two steam generators only). A three-pen pressure recorder is provided in the main control room for the steam generator steam pressure. A three-pen level recorder is provided in the main control room for the steam generators water level. Three flow recorders are provided in the main control room for the steam generators.

Drains from the feedwater heaters are controlled automatically to prevent the induction of water into the turbine while delivering an optimum amount of heat to the condensate flowing through the tube side of the heaters.

10.4.8 Steam Generator Blowdown System

The SGB system processes blowdown water from the steam generator to maintain steam generator water chemistry within specified limits.

10.4.8.1 Design Bases

The SGB system is designed in accordance with the following criteria:

1. General Design Criterion 1, as it relates to system components being designed, fabricated, erected, and tested for quality standards.

2. General Design Criterion 2, as it relates to system components designed to Seismic Category I requirements.

3. General Design Criterion 14, as it relates to secondary water chemistry control to ensure that the primary coolant boundary material integrity will be maintained.

4. System components are designed to the maximum temperatures and pressures expected to occur under normal and transient system operating conditions.

5. The system is designed to maintain optimum secondary side water chemistry during normal operation and under anticipated operational occurrences, such as a primary to secondary leakage and main condenser leakage.

6. The system piping connecting to the steam generators inside containment up to and including the first isolation valve outside the containment is designated Safety Class 2, Seismic Category I, and meets QA Category I standards.

7. The system is designed in accordance with the guidelines of Regulatory Guides 1.26, 1.29, and 1.143.

10.4.8.2 System Description and Operation

When used for secondary chemistry control, the SGB system shown on Figure 10.4-23, receives blowdown continuously from the steam generators at a maximum design rate of 97 gpm per steam generator. Normal flow rates vary depending on secondary water quality, condenser tube leakage, and primary-to-secondary leakage. The SGB flow is directed to the SGB flash tank where approximately 20 percent of the liquid flashes off to the second point feedwater heaters and is returned to the main condenser. The remaining liquid flows through two SGB heat exchangers where the SGB is cooled to less than 120°F. The blowdown is then directed to a duplex filter, and then a mixed bed ion exchange resin demineralizer and returned to the condenser. Demineralizer effluent water chemistry is continuously monitored by a local sample panel. Sample Panel effluent is directed to the turbine building floor drain system. If a high water level exists in the SGB flash tank, liquid can be drained to the fourth point through level control valves. On high-high water level in the SGB flash tank, blowdown is isolated from the steam generators. In the event of high blowdown temperature, flow is isolated to the demineralizers. The main feedwater system is described in Section 10.4.7.

Provision is made for draining a limited quantity of blowdown to the blowdown hold tanks via the blowdown drain tank cooler. Additionally, flashed blowdown vapor from the blowdown tank can be directed to the main condenser through a pressure control valve.

The SGB system also provides for mixing of the steam generator water when the steam generator is in wet layup. Nitrogen is supplied to the bottom blowdown connections on the steam generators with the equivalent of six bottles (230 scf/bottle) being released into the steam generator for mixing. The source of nitrogen is the nitrogen supply system described in Section 9.5.9.

The SGB system component design parameters are described in Table 10.4-12.

10.4.8.3 Safety Evaluation

The SGB system interfaces with other systems in such a way as to prevent overpressurization of systems designed to lower pressure and temperature conditions by use of normally closed valves. Interfaces with systems having a lower or higher safety class designation are accomplished by safety grade valves that isolate the safety portions from the nonsafety portions of the systems.

The SGB system connects to the extraction steam system through the second point feedwater heaters. Backflow into the high pressure turbine is prevented by non-return valves (NRVs) in the extraction steamlines. Overspeed of the turbine due to the failure of a NRV is not considered credible, because the extraction steamlines are supplied from the high pressure turbine, thus eliminating any flow path to the low pressure turbine in the turbine trip condition.

The SGB system lines penetrating the primary containment are isolated automatically, as described in the instrumentation section, to protect safety-related equipment located in the cable vault from the effects of a high energy line break. All of these isolation valves are powered from the safety-related buses. In these cases, where redundancy is provided, power is from opposite buses.

The SGB system maintains steam generator chemistry to reduce the possibility of corrosion of steam generator materials. The system can accommodate a long term primary to secondary leak rate of 1 gpm. The steam generator chemistry limits are provided in Table 10.4-13 and their bases are described in Section 5.4.2. The liquid waste management system (Section 11.2) can be utilized to assist processing of the blowdown water. Steam generator sampling is described in Section 9.3.2.1.

Oxygen concentration and pH are controlled by a separate chemical addition system, as described in Section 10.3.5.

The SGB system flash tank, drain tank cooler, filters, demineralizers, heat exchangers, and main feedwater heaters are located in the turbine building, a nonseismically designed building. Blowdown flow is not considered to be concentrated at this stage of the process and should not have an appreciable radioactive content. Provision has been made for sampling the turbine building drains prior to discharge.

Grab samples can be obtained and analyzed for radioactivity from sumps in the turbine building drains systems as required by the Offsite Dose Calculation Manual and in the event of a high activity alarm from the main steam discharge high range effluent monitor (Section 11.5.3). In the event of an alert alarm from the steam generator blowdown sample process monitor (Section 11.5.4), grab samples will be obtained every four hours while the secondary activity exceeds 1.0E-5 μCi/ml, and turbine building sumps are being discharged to the storm drainage system. A high activity alarm from the steam generator blowdown sample process monitor (Section 11.5.3) will isolate blowdown flow. If the turbine building drains activity concentrations at the drainage point are determined to exceed a gross concentration of 10^{-5} μCi/ml, the turbine building drains will be isolated from the storm drainage system, via manually operated isolation valves, and transferred to the liquid waste system for processing.

A failure modes and effects analysis (FMEA) to determine if the instrumentation and controls (I&C) and electrical portions meet the single failure criterion, and to demonstrate and verify how the General Design Criteria and IEEE Standard 279-1971 requirements are satisfied, has been performed on the SGB system. The FMEA methodology is discussed in Section 7.3.2. The results of these analyses can be found in the separate FMEA document (Section 1.7).

10.4.8.4 Inspection and Testing Requirements

The preoperational inspection and testing requirements for the SGB system are described in Section 14.2.12.

10.4.8.5 Instrumentation Requirements

Control switches with indicating lights are provided in the main control room for the SGB (outside containment) isolation valves. These valves are opened manually when the SGB system tank level is not high-high, the turbine auxiliary feedwater pump steam inlet valves are closed, the steam generator blowdown process sample radioactivity is acceptable, and the motor-driven auxiliary feedwater pumps are stopped. These valves will close automatically when there is a high-high level in the SGB tank, the turbine auxiliary feedwater pump steam inlet valves are opened, the steam generator blowdown process sample radioactivity is high, or the motor-driven auxiliary feedwater pumps are running.

Control switches with indicating lights are provided in the main control room for the SGB (inside containment) isolation valves. These valves are opened manually when the turbine auxiliary feedwater pump steam inlet valves are closed, the motor-driven auxiliary feedwater pumps are stopped, and the cable vault area temperature is not high. These valves will close automatically provided the turbine auxiliary feedwater pump steam inlet valves are opened, the motor-driven auxiliary feedwater pumps are running, or the cable vault area temperature is high.

Control switches with indicating lights are provided in the main control room for the SGB (inside containment) isolation valves. These valves will close when the cable vault area temperature is high.

A hand/auto control station and a selector switch with indicating lights are provided in the main control room for the blowdown tank drain valve to the condenser. This valve will be modulated to maintain level in the blowdown tank at set point. This valve receives a signal to shut if the blowdown temperature exceeds 120°F. This valve can be closed manually from the control room.

Selector switches with indicating lights are provided in the main control room for the SGB tank inlet valves. These valves are operated manually.

Control switches with indicating lights are provided in the main control room for the steam generator sample isolation valves. These valves are operated manually. These valves will close automatically when the auxiliary feedwater pumps are auto-started, or a steam generator has a high radiation sample.

Selector switches with indicating lights are provided on the sample system panel for the steam generator sample valves. These valves are operated manually and will be closed when their respective steam generator sample temperature is high or the auxiliary feedwater pumps are auto-started.

A control switch with indicating lights is provided in the main control room for the SGB tank outlet valve to the second point heaters. This valve may be operated manually or automatically when the second point heater backpressure is normal, the blowdown tank level is not extreme high, and the second point heaters level is not high-high. This valve will close automatically when the second point heater back pressure is not normal, the blowdown tank level is extreme high, or the second point heaters level is high-high.

A selector switch with indicating lights is provided in the Main Control Room for each of the SGB flash tank outlet valves to the fourth point heaters. These valves can open on a normal high level in the SGB flash tank provided the fourth point heater levels are not high.

A SGB flash tank level control valve to the SGB hold tanks is provided to transfer SGB to liquid waste if required. A selector switch with indicating lights is provided in the Main Control Room.

An SBG tank pressure control valve to the main condenser is provided to maintain the blowdown tank pressure at set point.

A level indicator is provided on the main board for the blowdown tank level.

Temperature differential indicators are provided locally for the SGB system temperatures.

Annunciation and associated computer inputs are provided in the main control room for SGB system trouble, which consists of SGB tank level high, SGB tank level low, and cable vault area temperature high.

Inputs needed, but not associated with the annunciation system, are provided in the computer for SGB tank level and SGB tank pressure.

10.4.9 Auxiliary Feedwater System

Following a loss normal feedwater, AFWS is designed to provide high pressure feedwater to the secondary side of the steam generators and maintain sufficient water level in the steam generators for reactor coolant heat removal, thus preventing an unacceptable temperature rise in the RCS. The AFWS is utilized during a main steamline break and feedwater line break, and provides a cooling source in the event of a small break LOCA. The AFWS can operate during start-up, hot standby, or cold shutdown conditions; however, this is not the intended function of this system.

10.4.9.1 Design Bases

The AFWS from and including the primary plant demineralizer water storage tank (PPDWST) to the auxiliary feedwater control valve is Safety Class 3 and is designed to Quality Group C standards, as defined in Regulatory Guide 1.26 and described in Section 3.2. Piping downstream of the auxiliary feedwater control valve is designed to Quality Group B standards. This portion of the AFWS is also seismically designed, as discussed in Section 3.7B.3. The PPDWST chemical addition system is designed to Quality Group D standards.

The AFWS is equipped with two half-capacity motor-driven pumps and one full capacity turbine-driven pump. Each half-capacity pump has sufficient capacity to remove decay heat. The turbine-driven pump is rated at 750 gpm at 2,760 feet TDH. The motor-driven pumps are each rated at 375 gpm at 2,760 feet TDH. The turbine-driven pump is powered independently of the motor-driven auxiliary feedwater pumps.

In the event of a line break in a feedwater supply line to a steam generator, each auxiliary feedwater supply line is equipped with a cavitating venturi capable of limiting flow to 310 gpm. Thus, sufficient auxiliary feedwater is available to the intact steam generators for reactor heat removal.

All redundant components and equipment are physically separated in individual cubicles, located at el 718 feet-6 inches of the safeguards building. The safeguards building is designed to preclude seismic, tornado, and missile damage.

The AFWS is designed in accordance with the following criteria:

1. General Design Criterion 2, as it relates to the structures and systems being capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, and floods.

2. General Design Criterion 4, as it relates to structures and systems being capable of withstanding the effects of external missiles, internally-generated missiles, pipe whip, and jet impingement forces associated with pipe breaks.

3. General Design Criterion 5, as it relates to the capability of shared systems and components important to safety to perform required safety functions.

4. General Design Criterion 19 and Branch Technical Position RSB 5-1 (USNRC 1981), as they relate to the capability of I&C for prompt hot shutdown of the reactor and potential capability of subsequent cold shutdown.

5. General Design Criteria 34 and 44 to ensure:

    a. The capability to transfer heat loads from the reactor system to a heat sink under accident conditions,

    b. Redundancy of components so that under accident conditions the safety function can be performed, assuming a single active component failure, and

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

6. General Design Criterion 45, as it relates to the design provisions made to permit periodic ISI of systems, components and equipment.

7. General Design Criterion 46, as it relates to design provisions made to permit operational, functional testing of the system and components to ensure:

   a. Structural integrity and system leaktightness,

   b. Operability and adequate performance of active system components, and

   c. Capability of the integrated system to function as intended during accident conditions.

8. Regulatory Guide 1.26, for the quality group classification of system components.

9. Regulatory Guide 1.29, for seismic design classification of system components.

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

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

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

13. Branch Technical Position ASB 10-1 (USNRC 1981), for auxiliary feedwater pump drive and power supply diversity.

14. The AFWS is designed to supply adequate minimum total flow, distributed to at least two steam generators, for the following transients as described in Chapter 15:

   a. Loss of normal feedwater,

   b. Loss of offsite power followed by reactor trip (results in a loss of normal feedwater),

   c. Secondary side pipe rupture, or

   d. Cooldown following steam generator tube rupture.

15. The PPDWST is designed to provide sufficient water for the unit to be maintained in a hot standby condition for at least 9 hours following a loss of normal feedwater and to allow

sufficient time to align a secondary supply for the AFWS for the preceding transients.

16. NUREG-0737 (USNRC 1980), Item II.E.1.1, for the performance of a simplified reliability analysis of the AFWS.

10.4.9.2 System Description

The AFWS, shown on Figure 10.4-24, consists of two motor-driven auxiliary feedwater pumps, one turbine-driven auxiliary feedwater pump, and the associated piping and valves necessary to connect the PPDWST to pump suctions and pump discharges to the feedwater system. The PPDWST is equipped with a chemical addition system for maintaining proper water quality.

The AFWS provides an emergency source of feedwater to the steam generators to act as heat sinks for sensible and decay heat removal from the reactor core under the following conditions: loss of power, feedwater system malfunction, main steam or feedwater line rupture, and LOCA.

The AFWS is also capable of providing feedwater to the three steam generators during start-up, hot standby, and cold shutdown conditions; however, these operations are not the intended function of the AFWS.

Each auxiliary feedwater pump takes suction directly through separate supply lines from the PPDWST. This tank is seismically designed and is enclosed in a missile and tornado-protected structure that is located in the yard. The 140,000 gallon PPDWST is maintained with at least 130,000 gallons of usable volume to satisfy the design basis of the AFWS. The tank is capable of maintaining hot standby for at least 9 hours.

The PPDWST is provided with connections to the 600,000 gallon DWST, which is used for normal makeup and makeup during hot standby or cold shutdown. The DWST contains up to 552,000 gallons of water which is transferrable to the PPDWST. Normal makeup and makeup during hot standby is performed with a 3-inch line connection between the two tanks that is located above the minimum required water level of the PPDWST. Makeup for cold shutdown is performed with an 8-inch connection between the two tanks. The PPDWST is initially filled with water from the 600,000 DWST. Water chemistry in the PPDWST is controlled thereafter by periodic sampling of the water and the addition of chemical treatment, as required. Chemical addition for the PPDWST is performed by utilizing a small circulating pump and injecting chemicals into the suction piping as required. Local samples are located on the suction piping of the circulating pump. The AFWS is also provided with separate chemical feed connections for chemical treatment that are located on individual AFWS supply lines.

A secondary Category I water supply for the AFWS is provided, with piping cross-connections to the SWS. These piping cross-connections are located in the safeguards building and located on the suction of each pump.

The turbine drive for the turbine-driven pump is supplied with steam from each of the steam generators, by pipe connections in each main steamline upstream of the main steam isolation trip valves (Section 10.3). The motor-driven auxiliary feedwater pumps receive power from redundant 4,160 V ac emergency buses.

The auxiliary feedwater pumps can be started either automatically or manually from the main control board. In addition, the pumps can be started manually from the emergency shutdown panel (ESP). Each motor-driven auxiliary feedwater pump delivers water to a separate auxiliary feedwater header, while the turbine-driven pump can be manually aligned to either one of the two headers. Each auxiliary feedwater pump is provided with a recirculation control valve, which is located on the discharge piping that recirculates back to the PPDWST. These valves are designed for a 30-percent minimum flow recirculation.

Piping from the auxiliary feedwater headers is arranged so that water can be supplied to each steam generator from either header. Parallel and redundant flow control valves are located in each supply line from the auxiliary feedwater headers. These valves, which are normally open, can be modulated by remote manual control from the main control room and are powered from emergency power buses. Downstream of the control valves, check valves are provided to prevent the loss of auxiliary feedwater in the event of an auxiliary feedwater header rupture.

Cavitating venturi flow elements are provided in the common auxiliary feedwater supply lines to each steam generator. These venturi orifices are designed to limit the flow to 310 gpm (choked flow). In the event of a main steamline or main feedwater line rupture that would result in a decrease of steam generator shell pressure, the venturis will prevent excessive flow to the depressurized steam generator.

The remote manual flow control valves, check valves, and venturi orifices are all located in the safeguards building.

Individual containment penetrations are provided for the auxiliary feedwater supply lines. Each auxiliary feedwater line is provided with a check valve inside the containment. The auxiliary feedwater supply lines feed the steam generators through individual connections on the main feedwater supply lines (Figure 10.4-24).

10.4.9.3 Safety Evaluation

The AFWS has sufficient design capacity with two half-capacity motor-driven pumps, one full-capacity turbine-driven pump, redundant water supply headers, redundant flow supply paths, redundant remote manual control valves, cavitating venturi flow orifices, and redundant emergency power supplies to withstand a single failure coincident with environmental occurrences and loss of offsite or standby power and still perform its intended safety function. Each half-capacity pump has sufficient capacity to remove decay heat.

The design of the AFWS meets the intent of NUREG-0660 (USNRC 1980), TMI Action Items II.K.1.5 and II.K.1.10.

Each auxiliary feedwater supply line is provided with a cavitating venturi flow orifice. If the pressure downstream of the flow orifice is reduced significantly, the cavitating venturi orifice will restrict the flow to 310 gpm. During a main steam or main feedwater line rupture coincident with a single failure of one of the auxiliary feedwater pumps, the minimum required flow to the intact steam generators will be maintained until the affected loop can be isolated. The AFWS can perform its required safety function for a secondary side pipe rupture while withstanding a single failure.

A FMEA to determine if the I&C and electrical portions meet the single failure criterion, and to demonstrate and verify how the GDC and IEEE Standard 279-1971 requirements are satisfied, has been performed on the AFWS. Similarly, a FMEA was performed on the mechanical portion of this system. The FMEA methodology is discussed in Section 7.3.2. The results of the I&C and electrical analysis can be found in the separate FMEA document (Section 1.7), while the mechanical analysis is incorporated in Appendix 10A.

A simplified reliability analysis of the AFWS has also been performed in accordance with the requirements of NUREG-0737 (USNRC 1980), TMI Action Item II.E.1.1, and is included in Appendix 10A. Also included in this appendix are the FMEA of the mechanical portion of AFWS and their computer-plotted fault-tree diagrams.

The auxiliary feedwater piping inside the containment, which is part of the main feedwater pressure boundary, is considered high energy and is analyzed accordingly, as discussed in Sections 3.6B.1 and 3.6B.2. The remainder of the AFWS does not operate during normal BVPS-2 operation and therefore is not considered for high energy line break analysis. This piping is considered moderate energy.

The pressurization of auxiliary feedwater piping between the inside containment check valves and outside containment check valves to main feedwater pressure does not constitute a high-energy classification of the containment isolation piping.

The loading due to a Design Basis Pipe Rupture (DBPR) on the Auxiliary Feedwater System is not considered concurrently with earthquake loading.

The analysis to demonstrate the capability of the AFWS to preclude hydraulic instabilities (water hammer) for all modes of operation is discussed in Section 3.7B.3.8. Additionally, as part of the water hammer analysis, pump and system testing is performed as discussed in Section 14.2.12.

10.4.9.4 Inspection and Testing Requirements

Preoperational tests are performed as described in Section 14.2.12. The ASME OM Code testing requirements are described in Chapter 16. In-service testing of pumps and valves is discussed in Section 3.9B.6, and ISI of Class 2 and 3 components is discussed in Section 6.6. Periodic sampling of water in the PPDWST is performed for hydrazine and/or ammonia requirements.

10.4.9.5 Instrumentation Requirements

The AFWS complies with the intent of NUREG-0737 (USNRC 1980), TMI Action Item II.E.1.2. The AFWS is further discussed in Section 7.3.

Control switches with indicating lights for the auxiliary feedwater pumps are provided on the main control board, the ASP, and on the ESP. Pushbuttons for transfer of control from the main control room to the ESP are provided at the ESP, with a manual reset at relay used to transfer control back to the main control room from the ESP. A pushbutton on the ASP will transfer control of one auxiliary feedwater pump to the ASP from the ESP or the main control room. A manual reset at relay will transfer control from the ASP back to the ESP or the main control room.

The motor-driven auxiliary feedwater pumps can be operated manually or automatically from either the main control room or the ESP. If no loss of power condition exists, the pumps are started automatically on a low-low steam generator level in two out of three steam generators, SI signal, automatic tripping of the main feedwater pumps, or AMSAC actuation. If a loss of power condition exists, the pumps are automatically started by the diesel loading sequence and any of the preceding conditions. Only one of the two motor-driven auxiliary feedwater pumps can be operated in the manual mode of operation from the ASP.

The turbine-driven auxiliary feedwater pump can be operated manually from the main control room or the ESP, but automatically only from the main control room. Automatically, a low-low level in any steam generator, an undervoltage on the reactor coolant pumps bus, SI signal, or AMSAC activation will start the pump by opening the solenoid-operated valves in the steam supply line, admitting steam to the turbine.

The motor-driven auxiliary feedwater pumps can be stopped manually only if there is no SI signal present. The turbine-driven auxiliary feedwater pump can be stopped manually from the main control room or ESP by closing the steam supply solenoid-operated valves, regardless of the presence of an automatic opening demand signal.

The auxiliary feedwater control valves are normally open and are provided with hand indicating controllers and open/close indicating lights in the main control room and the ESP. Two auxiliary feedwater control valves are provided with hand indicating controllers and open/close indicating lights at the ASP. These valves are all modulated manually by their respective controllers.

Control of the auxiliary feedwater control valves may be initiated from either the main control room or from the ESP. A pushbutton on the ESP will transfer control from the main control room to the ESP. A manual reset at relay is used to transfer control back to the main control room from the ESP. Control of two auxiliary feedwater control valves may be initiated from the ASP. A pushbutton on the ASP will transfer control to the ASP from the main control room or from the ESP. A manual reset at relay is used to transfer control back to the main control room or back to the ESP.

Annunciation is provided in the main control room for control at the ASP, control at the ESP, a steam generator auxiliary feedwater pump auto-start and to alert main control room operators that the TDAFWP steam supply solenoid-operated valve selector switches in the control room are in the (non-automatic) closed position. The preceding conditions are monitored by the BVPS-2 computer.

Computer inputs are provided for the auxiliary feedwater turbine-driven pump steam admission valves open/close position, auxiliary feedwater flow, main feedwater line pressure, auxiliary feedwater pumps lube oil discharge pressure, and motor-driven auxiliary feedwater pumps start/stop.

Indicators are provided in the main control room for auxiliary feedwater pump steam supply pressure, steam generator water level, and auxiliary feedwater flow.

Ammeters are provided in the main control room for the motor-driven auxiliary feedwater pumps.

Indicators are provided on the ESP for steam generator level and auxiliary feedwater flow.

Indication is provided on the ASP for auxiliary feed flow.

The PPDWST supply valve is modulated at set-point to maintain water level in the PPDWST.

A level recorder and level indicators are provided in the main control room for the PPDWST.

Annunciation is provided in the main control room for the PPDWST level. This condition is also monitored by the BVPS-2 computer system. An input not associated with the annunciation system is provided for the PPDWST level for monitoring by the BVPS-2 computer.

A control switch with indicating lights is provided locally for the PPDWST chemical feed line pump. This pump may be started manually, provided the PPDWST level is normal and the chemical feed line isolation valves are open. The chemical feed line pump may be stopped manually, or automatically when the PPDWST level is below normal or the chemical feed line isolation valves are closed.

Control switches with indicating lights are provided in the main control room for the PPDWST chemical feed line isolation valves. These valves are operated manually, provided the PPDWST level is normal. The valves may be closed manually or automatically when the PPDWST level is below normal.

10.4.10 Auxiliary Steam and Condensate System

The auxiliary steam and condensate system supplies heating and process steam throughout BVPS-2 to various equipment, and recovers the condensed steam from the equipment served.

The auxiliary steam and condensate system is NNS class.

10.4.10.1 Design Bases

The auxiliary steam and condensate system is designed in accordance with the following criteria:

1. Piping for this system is designed in accordance with ANSI B31.1, dated 1967, including all addenda through June 30, 1972, and is designated NNS class.

2. The system is capable of providing steam during normal operation, plant start-up, and plant shutdown.

3. The system has the capability to detect radioactive contaminants carried over from the equipment served.

10.4.10.2 System Description

The auxiliary steam supply header for BVPS-2 normally receives its steam requirements from one of four sources. During normal operation, the steam is supplied from the main steam manifold through a pressure reducing valve. When main steam pressure is too low, the main steam isolation valves are closed. During plant shutdown, steam is supplied from either the BVPS-1 main steam pressure reducing valve or from the auxiliary boilers. Auxiliary boilers are provided for both BVPS-1 and BVPS-2. Design data for BVPS-2 auxiliary boilers are provided in Tables 10.4-14, 10.4-15, 10.4-16. Connections are provided such that any boiler or auxiliary steam system can supply steam to either BVPS-1 or BVPS-2. The condensate will be returned to the unit that is providing the steam in order to maintain fluid inventories. In addition, the turbine gland steam system provides a backup source of steam for the auxiliary steam supply header during normal plant operation.

Auxiliary steam is used by and condensed in the following equipment:

1. Secondary plant demineralized water storage tank heater (Section 9.2.6),

2. Degasifier steam heaters (Section 11.3),

3. Evaporator reboilers (Section 11.2),

4. Boric acid batch tank (Section 9.3.4),

5. Carbon dioxide vaporizer,

6. Cask washdown area (Section 9.2.3),

7. Building heating heat exchangers

8. Condenser vacuum priming ejectors during start-up (Section 10.4.2),

9. Condenser steam jet air ejectors during normal operation (Section 10.4.2),

10. Turbine gland seal steam system during start-up and shutdown (Section 10.4.3), and

11. Containment vacuum ejectors during start-up (Section 6.2).

The condensate from the degasifier steam heaters is cooled by the primary component cooling water system (Section 9.2.2.1) so that it will not flash in the receiver. The condensate from the degasifier steam heaters and the boric acid batch tank is collected in the degasifier steam heater condensate receiver. From there it is pumped by one of the two degasifier condensate pumps to the auxiliary steam system condensate receiver tank.

The condensate from the evaporator reboilers is cooled by the turbine plant component cooling water system (Section 9.2.7) so that it will not flash in the receiver.

The condensate from the evaporator reboiler is collected in the evaporator reboiler condensate receiver. There it is pumped by one of the two evaporator reboiler condensate pumps to the auxiliary steam condensate receiver tank.

The auxiliary steam system condensate receiver tank collects the condensate from the flash tank of the building heating effluent, the secondary plant valve stem leakoff, and the SPDWST, in addition to the condensate pumped by the degasifier condensate pumps and the evaporator reboiler condensate pumps. This condensate is discharged to the main condenser. When auxiliary steam is supplied from BVPS-1, the condensate collected is returned to the condensate system of BVPS-1, and when auxiliary steam is supplied from BVPS-2, the condensate collected is returned to the condensate system of BVPS-2.

Condensate from the turbine gland seal system and the steam jet air ejectors is discharged directly to the condenser.

The containment vacuum ejectors and the condenser vacuum priming ejectors are used only during start-up. The steam used in these components is released to the atmosphere.

10.4.10.3 Safety Evaluation

The Category I air operated fail close valves required to automatically isolate an auxiliary steamline break in the auxiliary building are the only equipment in the auxiliary steam and condensate system that perform a safety-related function. Individually, either the BVPS-2 auxiliary boilers or the auxiliary steam supply from BVPS-1 can accommodate a normal plant shutdown and an orderly plant start-up, with normal building heating being provided. The auxiliary steam header is protected from a malfunction of the main steam pressure reducing valve by safety valves. Control valves in the auxiliary steam lines to the various heaters regulate the temperature in the equipment being serviced.

Radiation detection is accomplished in the auxiliary steam and condensate system by means of radiation monitors located in the condensate discharge path from degasifier and evaporator reboiler condensate pumps. In addition, radiation in auxiliary steam and in turbine exhaust resulting from excessive primary-to-secondary steam generator tube leakage will initially be detected by an in-line radiation monitor located in the gaseous discharge flow path from the air ejectors (Section 10.4.2).

To prevent safety-related equipment in the auxiliary building from exceeding individual environmental qualification conditions following an auxiliary steamline break in the auxiliary building, the auxiliary steam system is automatically isolated by in-line Category I air-operated fail close valves when the auxiliary building temperature exceeds 118.5°F.

10.4.10.4 Inspection and Testing Requirements

During the life of the plant, all portions of the system are either in continuous or intermittent operation and periodic tests are not required. Components are accessible for visual inspection during operation and following installation of spare parts or piping modifications, as necessary to confirm normal operation of the system.

Preoperational tests are performed as described in Section 14.2.12.

10.4.10.5 Instrumentation Requirements

Selector switches with indicating lights are provided on a local panel for the auxiliary steam condensate receiver pumps. A selector switch for mode control of the auxiliary steam condensate receiver pumps and the BVPS-1 and BVPS-2 auxiliary steam condensate level control valves is provided on the same local panel. Indicating lights are also provided locally for both BVPS-1 and BVPS-2 auxiliary steam condensate receiver level control valves.

The auxiliary steam system condensate receiver tank is normally drained to the condenser by a level control valve controlled by a local level controller and mode selection for BVPS-2. Under conditions when the auxiliary steam is supplied from BVPS-1, mode selection for BVPS-1 closes the preceding level control valve and allows another level control valve to modulate, by means of the previous level controller, to return the water to BVPS-1. One of the condensate receiver pumps in the manual BVPS-1 mode will run continuously to maintain a receiver level. The other condensate receiver pump set in the auto BVPS-1 mode will be on standby.

Selector switches with indicating lights are provided on local panels for the degasifier condensate pumps and the evaporator reboiler condensate pumps. These pumps can be operated manually or automatically. In the auto mode, these pumps run to maintain the level in their respective receivers, with the second pump in each system on standby.

Auxiliary steam header pressure is controlled by a local pressure indicating controller and a pressure control valve.

Drain coolers are provided to prevent flashing for the degasifier steam heater and evaporator receiver condensate receivers. The level in the drain coolers is controlled by level controllers and level control valves.

Annunciation is provided in the main control room for auxiliary steam header pressure low, evaporator reboiler or degasifier steam heater condensate receivers levels low-low or high-high, auxiliary steam condensate receiver level high-high or low-low, and auxiliary steam condensate receiver pumps motor thermal overload. Those conditions are also monitored by the BVPS-2 computer.

An indicator for auxiliary steam header pressure and a flow totalizing indicator for auxiliary steam header flow are provided in the main control room. Computer inputs are provided for auxiliary steam header flow and auxiliary steam header pressure.

Two air-operated isolation valves in series are provided to isolate auxiliary steam from the auxiliary building. Control switches with indicating lights are provided in the main control room for these isolation valves. These isolation valves can be controlled manually or automatically. In auto, these valves will close on an auxiliary building high temperature signal.

Selector switches with indicating lights are provided at local panels for the manually operated auxiliary boiler main steam stop valves.

10.4.11 Extraction Steam System

The extraction steam system directs steam from the high pressure and low pressure turbines to the feedwater heaters. The extraction steam is utilized for feedwater heating to increase cycle efficiency. The extraction steam system is shown on Figure 10.4-33, and the system flow to each feedwater heater is shown on the heat balance diagram (Figure 10.1-1).

10.4.11.1 Design Bases

The extraction steam system is designed in accordance with the following criteria:

1. Delivers extraction steam to the feedwater heaters over the full range of turbine operating loads.

2. Designed to prevent turbine overspeed from flashing heater drains after a turbine trip.

3. Designed to remove moisture from the turbine to provide protection for low pressure turbine blading.

4. Extraction steam piping is arranged and pitched to be self-draining away from the turbine to the feedwater heaters.

5. The extraction steam system is nonsafety-related and is classified as NNS class.

6. The extraction steam piping is designed in accordance with the code for power piping, ANSI B31.1, dated 1967, including all addenda through June 30, 1972.

10.4.11.2 System Description

The basic components of the extraction steam system are the MOVs used for isolation, the in-line NRV, and associated piping.

These components direct extraction steam from various high and low pressure turbine stages to the feedwater heaters.

During normal operation, extraction steam is supplied from the high pressure turbine to heat the feedwater flowing through the first and second point feedwater heaters. Extraction steam supplied from the low pressure turbines heats the feedwater flowing through the third, fourth, fifth, and sixth point feedwater heaters. The extraction steam is condensed in the feedwater heaters and recycled to the condensate system and the FWS (Section 10.4.7).

Each extraction line serving feedwater heaters external to the condenser neck is equipped with an MOV and an air-assisted swing check NRV. The NRV is provided to prevent overspeeding of the turbine by vapor flashed off from the heater on a turbine trip. The MOVs are manually closed using control switches in the main control room thereby preventing moisture carry-over from the feedwater heater to the turbine.

The sixth point feedwater heaters located in the condenser neck are not equipped with extraction line isolation MOVs or power-assisted NRVs. By cycle design, no cascaded drains or other external high enthalpy fluids are admitted to low pressure heaters in the condenser neck. Also, drain levels are maintained at a point external from the heater by loop seals. Consequently, there is a low inventory of fluid in the heater during operation so that overspeeding of the turbine as a result of flashing in the heater is prevented. Condensate inlet and outlet from the tube side of the heater can be manually isolated using control switches in the main control room, thus preventing water induction from either malfunctioning drains (steam condensation will stop when tube side flow stops) or from a tube rupture.

10.4.11.3 Safety Evaluation

The extraction steam system has no safety function and its failure will not affect the safety functions of other equipment. Removal of extraction steam from the turbines is required for moisture removal and the corresponding protection against erosion of the low pressure turbine blading.

If the turbine trips, the extraction line NRVs will automatically close and their associated extraction line drain valves will open. This prevents condensate flashing in the feedwater heaters from flowing back to the turbine and causing a turbine overspeed condition.

Details concerning conditions causing turbine trip are discussed in Section 10.2.

The sixth point feedwater heaters that are located within the condenser neck, which are not provided with extraction line MOVs and NRVs, do not pose a safety problem for the turbines as heater water inventories are minimized and have relatively low enthalpy values.

10.4.11.4 Inspection and Testing Requirements

Periodic observations and monitoring of the system parameters are performed during operation.

Components are accessible for visual inspections during operation, and following installation of spare parts or piping modifications, to confirm normal operation of the system.

10.4.11.5 Instrumentation Requirements

Control switches with indicating lights are provided in the main control room for the extraction steam isolation valves for the first, second, third, fourth, and fifth point feedwater heaters. These valves can be closed and adjusted to maintain feedwater heater levels, utilizing control switches in the main control room. The extraction steam isolation valves are normally open during BVPS-2 operation. Downstream of each extraction steam isolation valve, an NRV is provided. Upon a turbine trip signal, a solenoid valve will be de-energized, causing the NRV to vent air, which causes the spring to drive the clapper in the close direction. When the turbine is latched, a fluid-operated air pilot valve admits air to all NRVs, allowing the clapper to also swing freely. A test lever is provided locally at each NRV, which admits air to both sides of the piston so that the spring will be able to drive the piston to assist in the closing.

Control switches with indicating lights are provided in the main control room for the extraction line drain valves, which are grouped together for their respective heaters. On the first and second point heaters, there is a drain valve upstream of the extraction steam isolation valve, a drain valve between the extraction steam isolation valve and the extraction steam NRV, and a drain valve downstream of the extraction steam NRV. All of the drain valves will be opened provided that the control switch is in open, an extreme high level in its respective heater, or a turbine trip exists. The drain valve upstream of the extraction steam isolation valve will also open when the extraction steam isolation valve is closed. The drain valve between the extraction steam isolation valve and the extraction steam NRV, and the drain valve downstream of extraction steam NRV will be closed provided that the control switch is in close, the level in the respective heater is below the extreme high level, and there is no turbine trip signal present. The drain valve upstream of the extraction steam isolation valve will close with the NRVs provided that the control switch is in close, the level in the respective heater is below the extreme high level, no turbine trip signal is present, and the extraction steam isolation valve is opened.

Control switches with indicating lights are provided in the main control room for the extraction line drain valves, which are grouped together for their respective heaters, on the third, fourth, and fifth point heaters. There is a drain valve upstream of the extraction steam isolation valve, and a drain valve between the extraction steam isolation valve and extraction steam NRV. The drain valve upstream of the extraction steam isolation valve will also open when the extraction steam isolation valve is closed. The drain valve between the extraction steam isolation valve and the extraction steam NRV will close when the control switch is in close, the level in the respective heater is below the extreme high level, and there is no turbine trip signal. The drain valve upstream of the extraction steam isolation valve will also close provided the previous conditions exist and the extraction steam isolation valve is open.

Annunciation is provided in the main control room for first point high pressure feedwater heater level extremely high, second point low pressure feedwater heater level extremely high, third point low pressure feedwater heater level extremely high, fourth point low pressure feedwater heater level extremely high, fifth point low pressure feedwater heater level extremely high, and the sixth point low pressure feedwater heater level extremely high, all of which are monitored by the BVPS-2 computer. The extraction steam pressure and temperature going to each feedwater heater are also monitored by the BVPS-2 computer. A multipoint temperature recorder is provided in the main control room for recording of the extraction steam line drains temperature.

10.4.12 References for Section 10.4

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Tables for Section 10.4

TABLE 10.4-1

MAIN CONDENSER
DESIGN PARAMETERS AND PERFORMANCE CHARACTERISTICS

Characteristic	Parameter
Performance Characteristics	
Steam condensed, normal operation (lb/hr)	6,713,000
Steam condensed, turbine bypass (lb/hr)	5,500,000
Circulating water flow rate (gpm)	480,400
Heat transfer (Btu/hr)	6.286×10^9
Back pressure (in Hg abs)	2.99
Hotwell temperature (°F)	114.9
Circulating water temperature (°)	81

Refer to UFSAR Figure 10.1-1 for operating conditions for the NSSS thermal power of 2910 MWt.

Characteristic	Parameter
Design Parameters	
Number of shells	2
Passes per shell	1
Surface area (ft^2)	720,000
Number of tubes	67,920
Tube material	304 Stainless steel
Tube OD (in)	3/4
Effective length per tube (ft-in)	54-2
Hotwell capacity (minimum)	4 min full flow /71,000 gal

TABLE 10.4-2

CIRCULATING WATER SYSTEM
COOLING TOWER PUMP CHARACTERISTICS

Component	Parameter
Cooling Tower Pumps	
Quantity	4
Capacity (gpm) each	126,850
Design suction temperature (°F)	120
Total dynamic head (4 pump operation) (ft)	73

TABLE 10.4-3

NATURAL DRAFT COOLING TOWER
DESIGN PARAMETERS

Component	Design Parameters
Natural Draft Cooling Tower	
Quantity	1
Flow (gpm)	507,400
Range (°F)	25.5
Approach (°F)*	16
Dry bulb temperature (°F)*	87
Wet bulb temperature (°F)*	74
Exit air volume (cfm)*	35,000,000
Exit air temperature (°F)*	106
Evaporation loss (gpm)*	10,500
Drift loss (%)	0.013
Top diameter (ft)	260
Throat diameter (ft)	243.5
Height (ft)	502
Bottom diameter (ft)	422

NOTE:

*Design conditions.

TABLE 10.4-4[7]

CHEMICAL ANALYSIS OF WATER

Parameter[1]	Ohio River Water Quality[2] Avg	Min	Max	Closed-Loop Circulating Water Quality Avg[3]	Min[4]	Max[5]
Alkalinity, methyl orange (as $CaCO_3$)	23.1	6.0	33.0	41.6	9.0	79.2
Acidity, total (as $CaCO_3$)	5.4	2.0	12.0	9.7	3.0	28.8
Hardness (as $CaCO_3$)	100.4	66.0	174.0	180.7	99.0	417.6
Calcium	27.5	17.0	50.0	49.5	25.5	120.0
Magnesium	7.5	4.5	12.0	13.5	6.8	28.8
Suspended solids	20.6	1.0	44.0	37.1	1.5	105.6
Dissolved solids	202.8	97.0	347.0	365.0	145.5	832.8
COD	6.9	5.0	11.0	12.4	7.5	26.4
BOD	<1.0	<1.0	7.0	<1.8	<1.5	16.8
Total organic carbon	4.7	1.0	10.0	8.5	1.5	24.0
Iron, total	1.5	0.1	3.8	2.7	0.15	9.1
Iron, soluble	<0.05	<0.05	<0.05	<0.09	<0.08	<0.12
Copper	<0.03	<0.02	0.48	<0.05	<0.03	1.15
Manganese	0.54	0.28	0.88	0.97	0.42	2.11
Chromium, total	<0.03	<0.03	0.03	<0.05	<0.05	0.07
Chromium, hexavalent (μg/l)	<2	<2	3	<3.6	<3.0	7.2
Nickel	<0.01	<0.01	0.02	<0.02	<0.02	0.05
Zinc	0.09	0.03	0.23	0.16	0.05	0.55
Aluminum	0.42	<0.1	0.9	0.76	<0.15	2.16
Sodium	18.6	10.0	31.0	33.5	15.0	74.4
Potassium	3.4	2.0	5.3	6.1	3.0	12.7
Sulfate	86.6	51.5	162.0	155.9	77.3	388.8
Phenol (μg/l)	6	<1	17	10.8	<1.5	40.8
Surfactant (μg/l)	17	<10	40	31	<15	96
Nitrogen, Kjeldahl	0.91	0.34	1.50	1.64	0.51	3.60
Ammonia (as NH_3)	0.64	0.35	1.04	1.15	0.53	2.50
Nitrate (as NO_3)	5.8	3.5	8.0	10.4	5.3	19.2
Nitrite (as NO_2)	0.13	0.07	2.18	0.23	0.11	5.23
Phosphate, total (as PO_4)	0.30	0.09	0.51	0.54	0.14	1.22
Phosphate, ortho (as PO_4)	0.06	<0.05	1.16	0.11	0.08	2.78
Silica, total (as SiO_2)	8.0	4.9	17.1	14.4	7.4	41.0
Mercury, aqueous (μg/l)	<1.3	<0.2	8.3	2.3	<0.3	19.9
Mercury, sediment (μg/l)	164.8	73.0	299.0	-	-	-
Chlorine, free residual[6]	0	0	0	0	0	0
pH, units	-	6.6	7.6	-	6.0	9.0

TABLE 10.4-4 (Cont)

NOTES:

1. All concentrations are expressed in mg/l unless indicated otherwise.
2. NUS Corporation 1974 Aquatic Ecology Study, Baseline Water Quality Data, Annual Report.
3. Average blowdown concentrations based on cooling tower concentration factor of 1.8 and average river water concentration.
4. Minimum blowdown concentrations based on cooling tower concentration factor of 1.5.
5. Maximum blowdown concentrations based on cooling tower concentration factor of 2.4 maximum river water concentration.
6. Average and maximum values during system chlorination. Chlorine will be present in the discharge from each unit for no more than 2 hours per day.
7. Table 10.4-4 contains historical data only.

TABLE 10.4-8

CONDENSER COOLING WATER ANALYSIS
AVERAGE PARAMETERS

Chemical Components	Normal Operation
pH at 77°F	6.0 to 9.0
Total dissolved solids (ppm)	365
Suspended solids (ppm)	37.1
Calcium (Ca) (ppm)	49.5
Magnesium (Mg) (ppm)	13.5
Silica (SiO_2) (ppm)	14.4
Chloride (Cl) (ppm)	27
Sulfate (SO_4) (ppm)	155.9
Bicarbonate (HCO_3) (ppm)	42
Sodium (Na) (ppm)	33.5

TABLE 10.4-9

STEAM GENERATOR BLOWDOWN ANALYSIS
AT NORMAL OPERATIONS

Chemical Component	Normal Operation

Refer to UFSAR Section 10.3.5, Water Chemistry

TABLE 10.4-12

STEAM GENERATOR BLOWDOWN SYSTEM
COMPONENT DESIGN PARAMETERS

<u>Steam Generator Blowdown Tank</u>	
Capacity (gal)	2,500
Design pressure (psig)	275
Design temperature (°F)	410
Design code	ASME VIII
<u>Steam Generator Blowdown Drain Tank Cooler</u>	
Total duty (Btu/hr)	5.035×10^6
Inlet temperature (blowdown) (°F)	397
Inlet temperature (component cooling water) (°F)	95
Outlet temperature (blowdown) (°F)	180
Outlet temperature (component cooling water) (°F)	120
Design code	ASME VIII
<u>Steam Generator Blowdown Demineralizer Heat Exchanger</u>	
<u>2BDG-E22</u>	
Total Duty (Btu/hr)	35.779×10^6
Inlet temperature (blowdown) (°F)	410
Inlet temperature (condensate) (°F)	155
Outlet temperature (blowdown) (°F)	150
Outlet temperature (condensate) (°F)	155
Design Code	ASME VIII
<u>2BDG-E23</u>	
Total Duty (Btu/hr)	3.690×10^6
Inlet temperature (blowdown) (°F)	150
Inlet temperature (component cooling water) (°F)	115
Outlet temperature (blowdown) (°F)	120
Outlet temperature (component cooling water) (°F)	115
Design Code	ASME VIII

TABLE 10.4-13

STEAM GENERATOR STEAM SIDE AND FEEDWATER CHEMISTRY SPECIFICATIONS

	Cold Hydro/ Cold Wet Layup	Hot Functional/ Hot Shutdown/ Hot Standby		Start-up From Hot Standby				Normal Power Operation			
Chemistry	Blowdown	Blowdown		Feedwater		Blowdown		Feedwater		Blowdown	
Parameter	Control	Control	Expected	Expected	Control	Control	Expected	Expected	Control	Control	Expected
pH @ 25°C											
Free hydroxide as ppm $CaCO_3$											
Cation conductivity mhos/cm @ 25°C											
Total conductivity mhos/cm @ 25°C	Refer to UFSAR Section 10.3.5, Water Chemistry										
Sodium, ppm											
Chloride, ppm											
NH_3, ppm											
Hydrazine, ppm											
Dissolved oxygen, ppb											
SiO_2, ppm											
Fe, ppb											
Cu, ppb											
Suspended solids, ppm											
Blowdown rate, gpm/SG											

TABLE 10.4-14

AUXILIARY BOILERS
PERFORMANCE CHARACTERISTICS

Condition	Parameters
Steam output	150,000 lb/hr
Boiler operating pressure/temperature	150 psig/366°F
Auto boiler blowdown	7,500 lb/hr
Boiler feedwater temperature	228°F
Burner turndown ratio	15,000 lb/hr to 10,000 lb/hr
Overall unit efficiency at 100% load	80.3%
Exilt gas temperature at 80°F inlet air	601°F

TABLE 10.4-15

AUXILIARY BOILERS
DESIGN PARAMETERS

Component	Parameter
Make	Babcock-Wilcox
Type	D type, FM
Design pressure waterside (psig)	250
Design pressure gas side (wg) (in.)	18
Drum material, ASME designation	SA515GR70/SA106[(1)]
Upper drum I.D. (in.)/thickness (in.)	48/1.03
Lower drum I.D. (in.)/thickness (in.)	24/0.0875
Membrane type construction	Side walls, rear wall, floor and ceiling
Refractory wall construction	Front wall

NOTES 1. Materials listed in this table may have been replaced with materials of equivalent design characteristics. The term equivalent is described in UFSAR Section 1.12, "Equivalent Materials".

TABLE 10.4-16

AUXILIARY BOILERS
PRINCIPAL COMPONENTS AND DESIGN PARAMETERS

Component	Design Parameters
Deaerator	
Quantity	1
Capacity (lb/hr)	150,000
Operating pressure (psig)	5
Operating temperature (°F)	228
Boiler feed pumps	
Quantity	2
Gpm (each)	330
Head (ft)	550
Horsepower	100
Underground fuel oil tanks	
Quantity	5
Dimensions (ft, each)	12 (diameter) x 63 (length)
Capacity (gal, each)	48,000
Underground fuel oil transfer pumps	
Quantity	2
Gpm (each)	30
Head (ft)	125
Horsepower	3
Fuel oil day tank	
Quantity	1
Design capacity (gal)	596
Fuel oil pumps (boilers)	
Quantity	2
Gpm (each)	24
Head (ft)	460
Horsepower	7.5

TABLE 10.4-16 (Cont)

Component	Design Parameters
Chemical feed system	
Number of chemical skids	2
Feed tanks per skid	1
Capacity (gal)	100
Feed pumps per skid	2
GPH (each)	5
Horsepower	0.5
Auxiliary boiler blowdown tank	
Quantity	1
Design capacity (gal)	483
Auxiliary boiler blowdown vent condenser	
Quantity	1
Design pressure shell (psig)	150
Design pressure tube (psig)	150
Fluid condensed	steam
Flow (lb/hr)	1414.5

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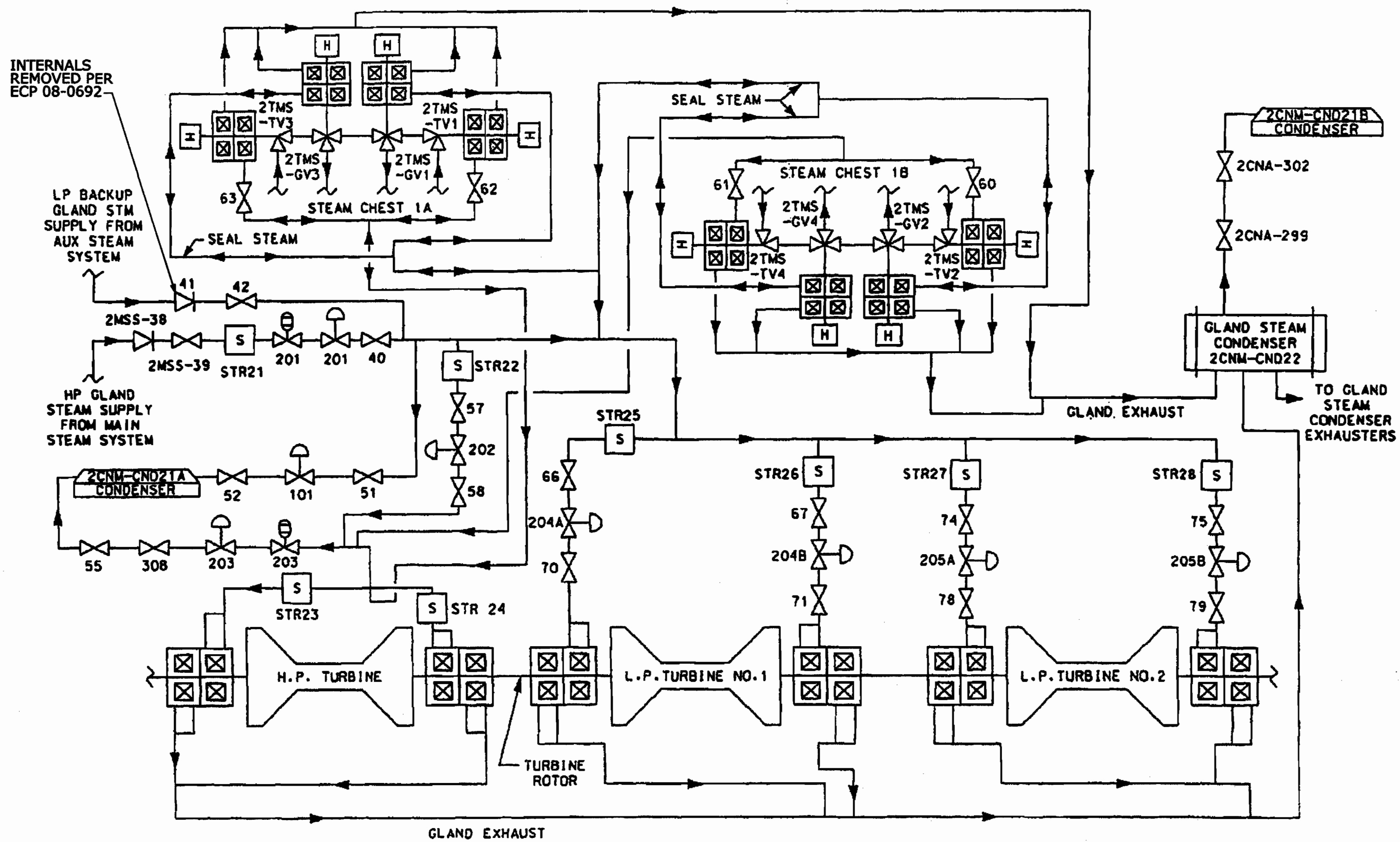

ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2GSS" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-1

TURBINE GLAND SEAL STEAM SYSTEM

REFERENCE: STATION DRAWINGS OM 26-2 AND OM 26-3

BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

P&ID–FSAR CROSS-REFERENCE KEY

P&ID NO.	FSAR FIGURE NO.
06–1A	5.1–2
06–1B	5.1–3
06–1C	5.1–4
06–2A	5.4–8
06–2B	5.4–9
06–4A	5.1–5
06–4B	5.1–6
06–4C	5.1–7
07–1	9.3–21
07–2	9.3–22
07–3A	9.3–23
07–3B	9.3–24
07–4	9.3–25
08–1A	9.3–26
08–1B	9.3–27
08–2	9.2–30
09–1	9.3–13
09–2	9.3–14
09–3A	9.3–15
09–3B	9.3–16
10–1	5.4–4
11–1	6.3–1
11–2	6.3–2
11–3	9.5–13
11–4	6.3–3
12–1	9.5–15
13–1	6.2–122
13–2	6.2–121
14A–1A	9.3–6
14A–1B	9.3–7
14A–2	9.3–8
14B–1	9.3–9
14B–2	9.3–10
14C–1	9.3–11 SHT1
14C–2	9.3–11 SHT2
15–1	9.2–10
15–2	9.2–11
15–3	9.2–12
15–4	9.2–13
15–5	9.2–21
15–6	9.2–14
15–7	9.2–15

P&ID NO.	FSAR FIGURE NO.
15–8	9.2–16
16–1	6.5–2
16–2	6.5–3
17–1	11.2–1
18–1	11.4–1
18–2	11.4–2
19–1	11.3–1
19–2	11.3–2
19–3	11.3–3
20–1	9.1–4
21–1A	10.3–1
21–1B	10.4–2
21–1C	10.3–3
21–1D	10.3–4
21–1E	10.3–2
21–2	9.5–14
22–1A	10.4–13
22–1B	10.4–12
22–2A	10.4–7
22–2B	10.4–8
22–3A	10.4–10
22–3B	10.4–11
22–4	10.4–9
22–5	9.3–5
23A–1A	10.4–33
23A–1B	10.4–34
23A–1C	10.4–35
23A–2	10.4–36
23B–3A	10.4–17
23B–3B	10.4–18
23B–4A	10.4–19
23B–4B	10.4–20
23B–5A	10.4–21
23B–5B	10.4–22
24–1A	10.4–15
24–1B	10.4–14
24–1C	10.4–16
24–2	10.4–24
25–1	10.4–23
25–2	11.2–2

P&ID NO.	FSAR FIGURE NO.
25–3A	11.2–3
25–3B	11.2–4
25–4	11.2–5
25–5	11.2–6
26–1A	10.2–2
26–1B	10.2–3
26–2	10.2–7
26–3	10.4–1
26–4	10.2–1
26–6	10.2–6
26–7	10.2–8
26–17	9.4–16
27–1	10.4–25
27–2	10.4–26
27–3	10.4–32
27–4	10.4–26A
27B–1	10.4–37
27B–2	10.4–38
27B–3	10.4–39
27B–4	10.4–40
28–1A	9.2–28
28–1B	9.2–29
29–1	9.2–17
29–2	9.2–18
29–3	9.2–19
29–4	9.2–20
30–1	9.2–1
30–2	9.2–2
30–3	9.2–3
30–4	9.2–4
30–5	9.2–5
31–1	10.4–3
31–2	10.4–4
31–3	10.4–5
31–4	10.4–6
32–1	9.2–22
32–3	10.3–5
32–4	9.2–27
33–1A	9.5–1
33–1B	9.5–2
33–2	9.5–3
33–3	9.5–4
33–4A	9.5–5
33–4B	9.5–6
33–5	9.5–6A
34–1	9.3–1
34–2	9.3–2
34–3	9.3–3
34–4	9.3–4

P&ID NO.	FSAR FIGURE NO.
35–2	10.2–9
35–3	10.2–10
36–9	9.5–7
36–10	9.5–12
36–11	9.5–10
36–12A	9.5–8
36–12B	9.5–9
36–13	9.5–11
41A–1	10.4–27
41A–2	10.4–28
41A–3A	10.4–29
41A–3B	10.4–30
41A–4	10.4–31
41C–1	9.2–24
41C–2	9.2–25
41C–3	9.2–26
41D–1	9.3–17
41D–2	9.2–23
41D–3	9.3–18
41D–5	9.3–20
41D–6	9.3–19
44A–1	9.4–2
44A–2	9.4–1
44A–4	9.4–3
44B–1	9.4–12
44B–3A	9.4–15
44B–3B	9.4–14
44C–1	9.4–9
44C–2	9.4–10
44D–1A	9.4–4
44D–1B	9.4–5
44D–2	9.4–6
44F–1	9.4–11
44F–2	9.4–7
44F–3	9.4–13
44F–4	9.4–8
44G–1	9.4–17
44G–2	9.4–18
44G–3	9.4–19
44G–4	9.4–20
46–1	6.2–131
59A–1	9.5–2A SH1
59B–1	9.5–2A SH2

NO. 10080–0M–21–1B

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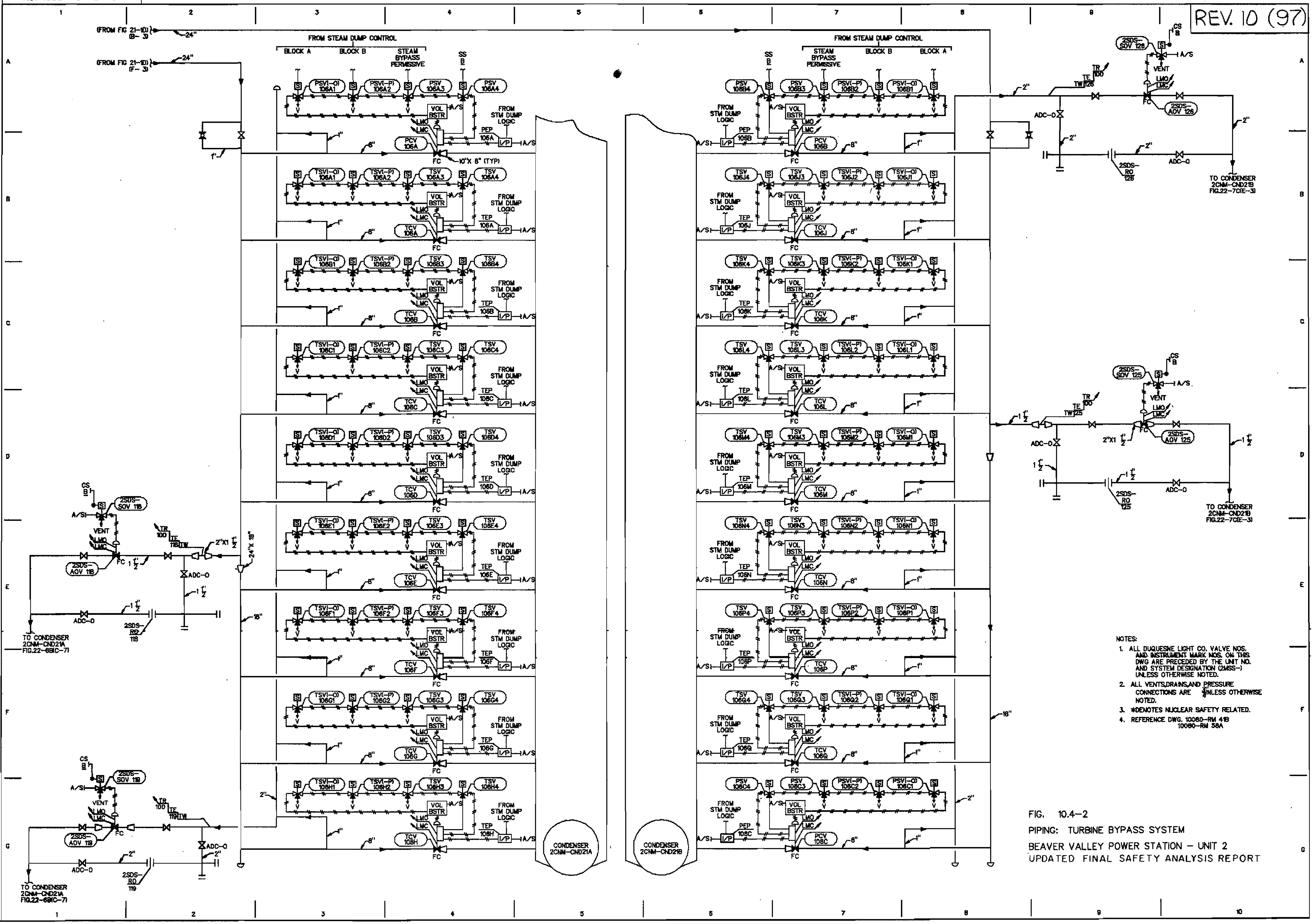
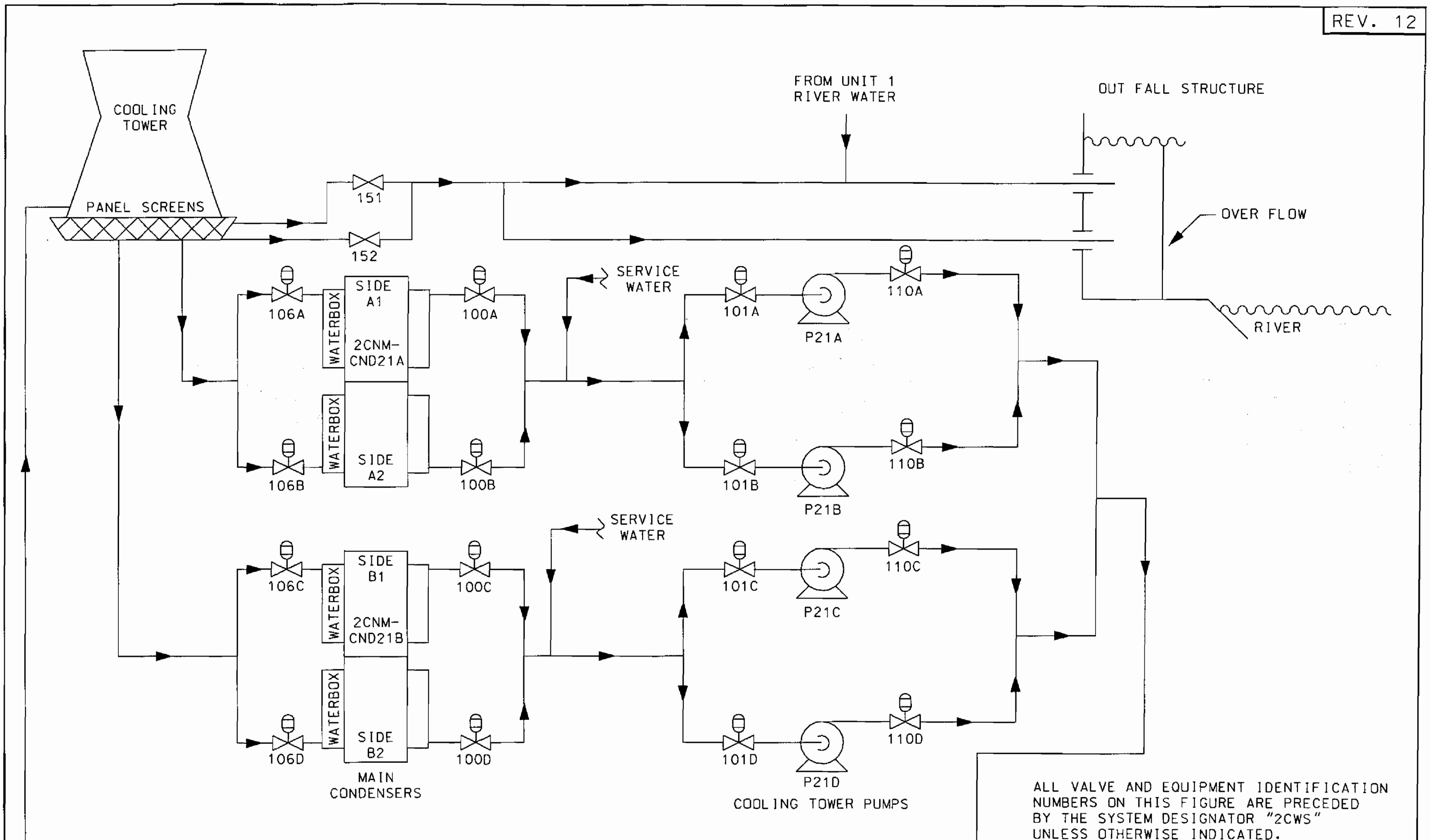


FIG. 10.4–2

PIPING: TURBINE BYPASS SYSTEM

BEAVER VALLEY POWER STATION – UNIT 2

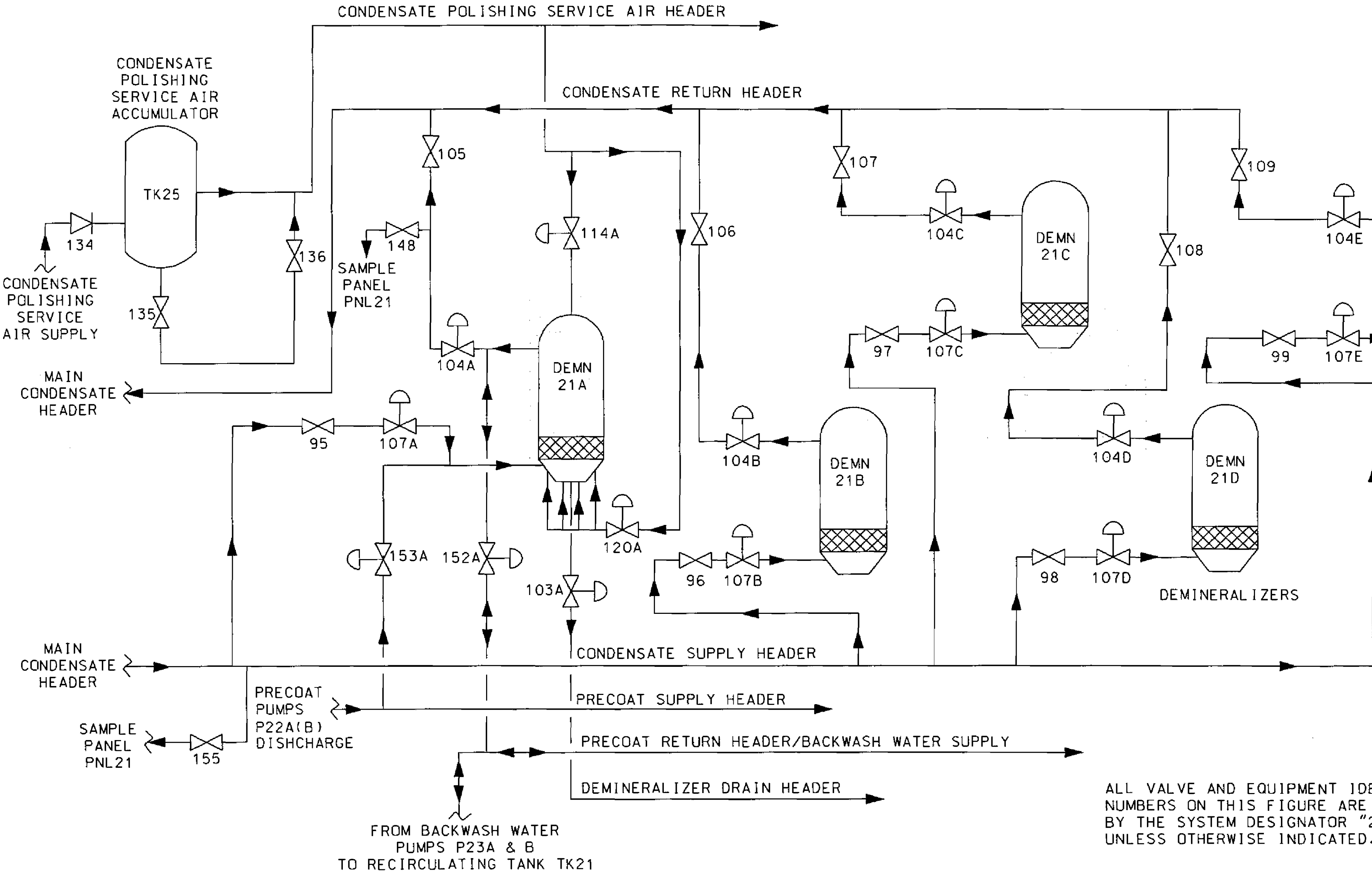
UPDATED FINAL SAFETY ANALYSIS REPORT



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2CWS" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-3
CIRCULATING WATER SYSTEM
REFERENCE: STATION DRAWINGS OM 31-1 AND OM 31-2
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV. 12

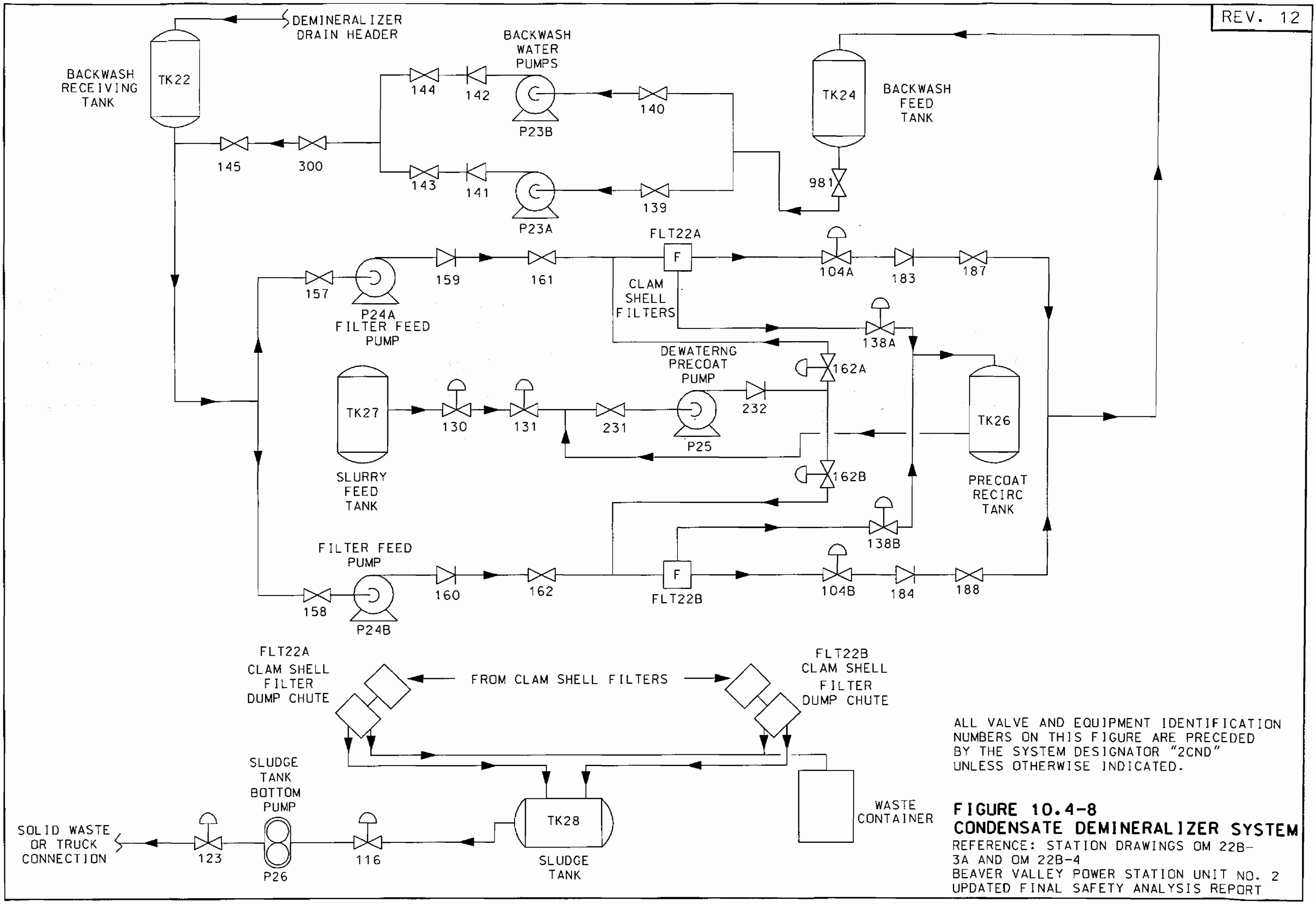


ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2CND" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-7
CONDENSATE DEMINERALIZER SYSTEM

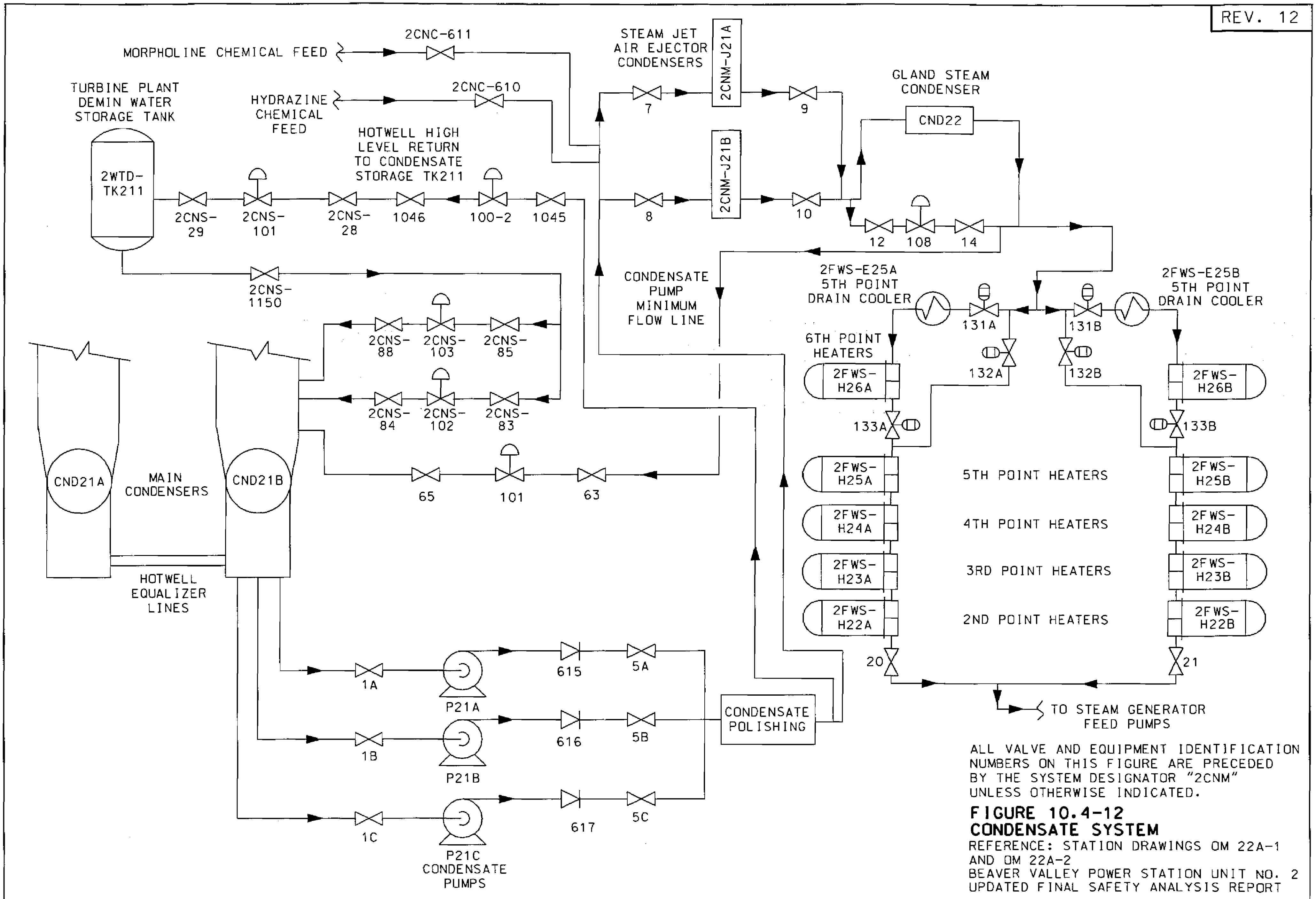
REFERENCE: STATION DRAWINGS OM 22B-1 AND OM 22B-2
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

NOTE: VALVES 103A, 114A, 148, 152A, 153A AND THE ASSOCIATED PIPING AND CONNECTIONS FOR DEMN-21A ARE TYPICAL FOR ALL OF THE DEMINERALIZERS.



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2CND" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-8
CONDENSATE DEMINERALIZER SYSTEM
REFERENCE: STATION DRAWINGS OM 22B-3A AND OM 22B-4
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

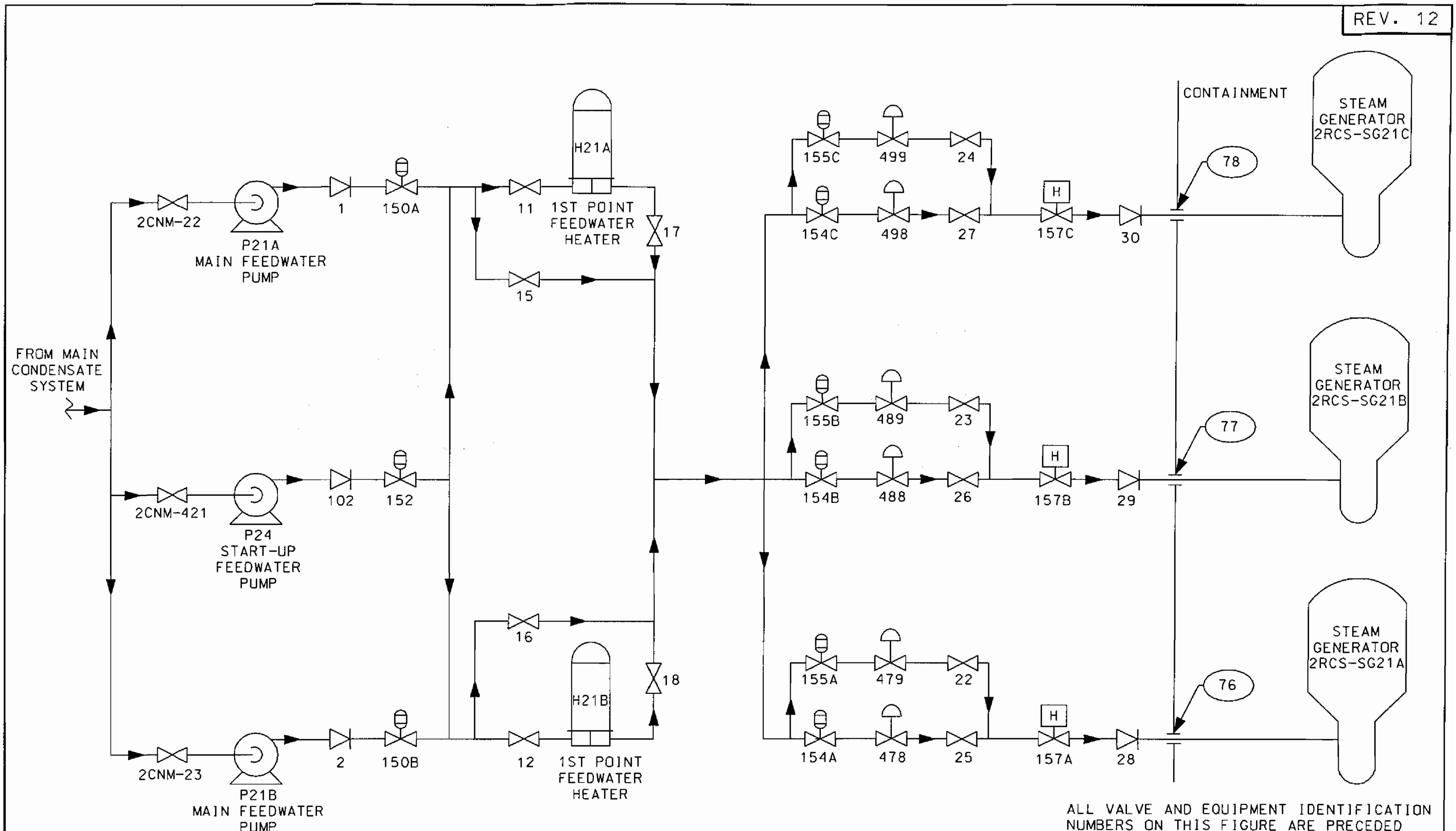


ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2CNM" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-12
CONDENSATE SYSTEM

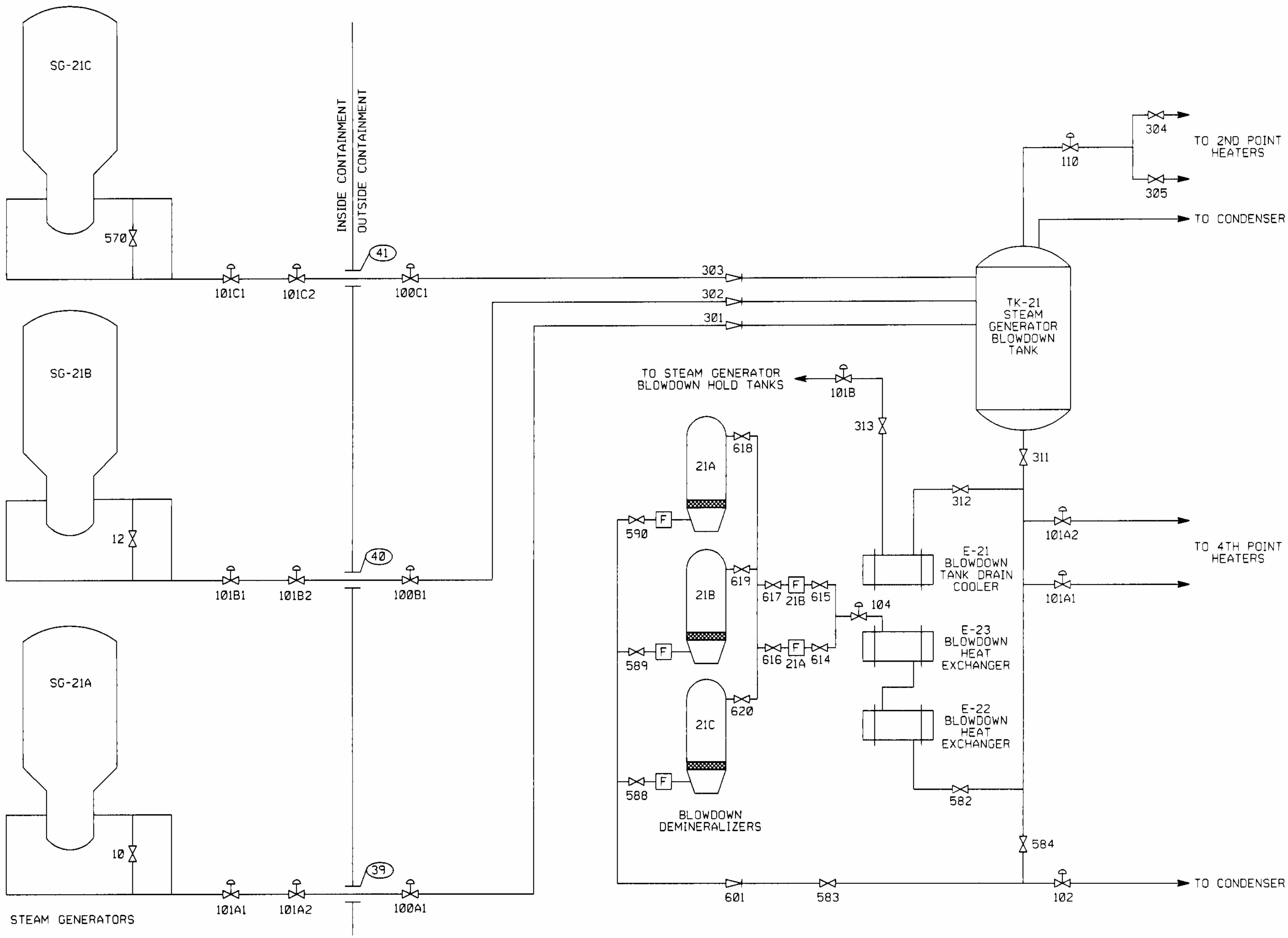
REFERENCE: STATION DRAWINGS OM 22A-1 AND OM 22A-2

BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2FWS" UNLESS OTHERWISE INDICATED.

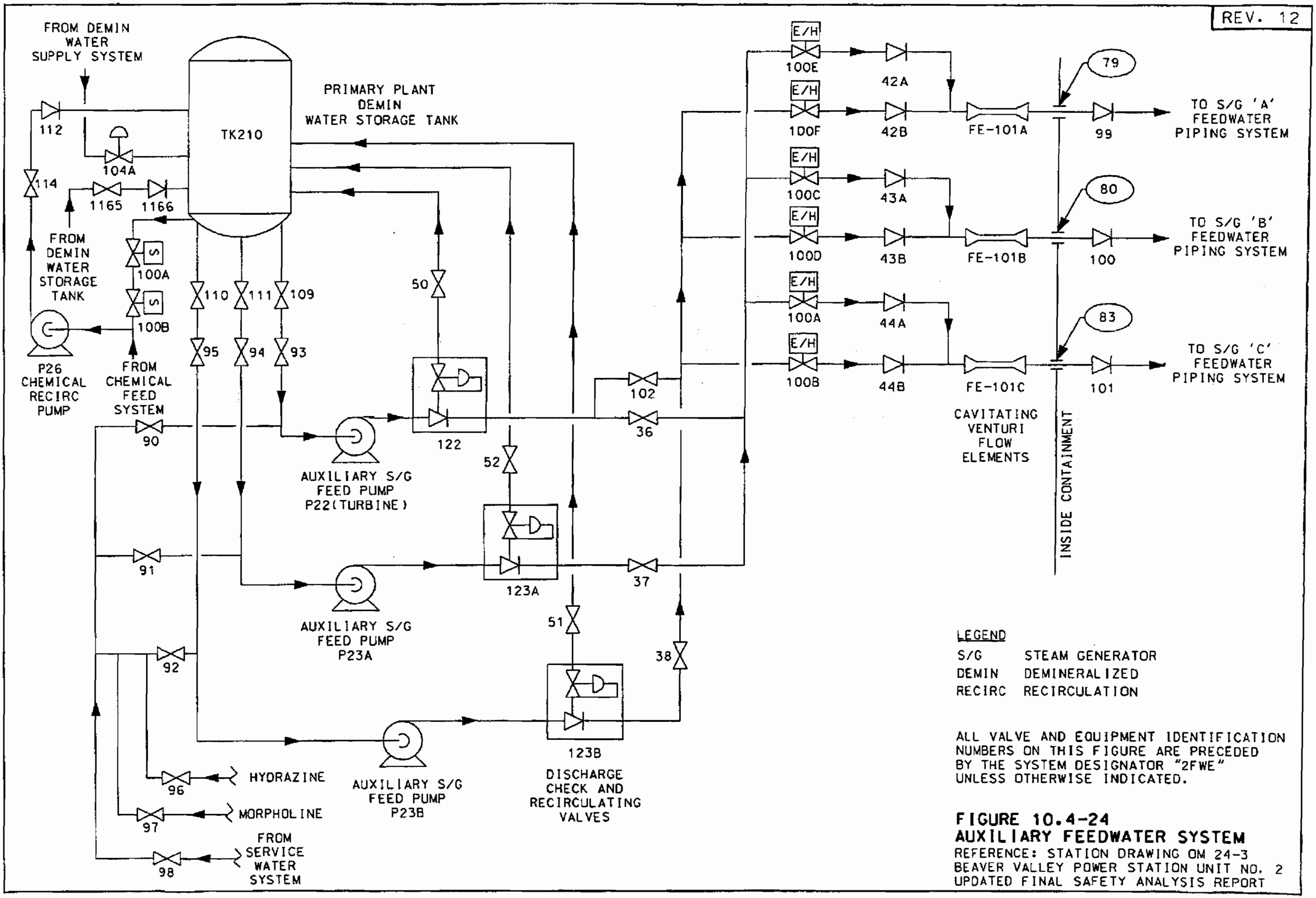
FIGURE 10.4-14
FEEDWATER SYSTEM
REFERENCE: STATION DRAWINGS OM 24-1 AND OM-24-2A
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS DIAGRAM ARE PRECEDED BY THE SYSTEM DESIGNATOR '2BDG' UNLESS OTHERWISE INDICATED.

FIGURE 10.4-23
STEAM GENERATOR BLOWDOWN

REFERENCE DRAWINGS OM 25-1 AND 25-1A
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

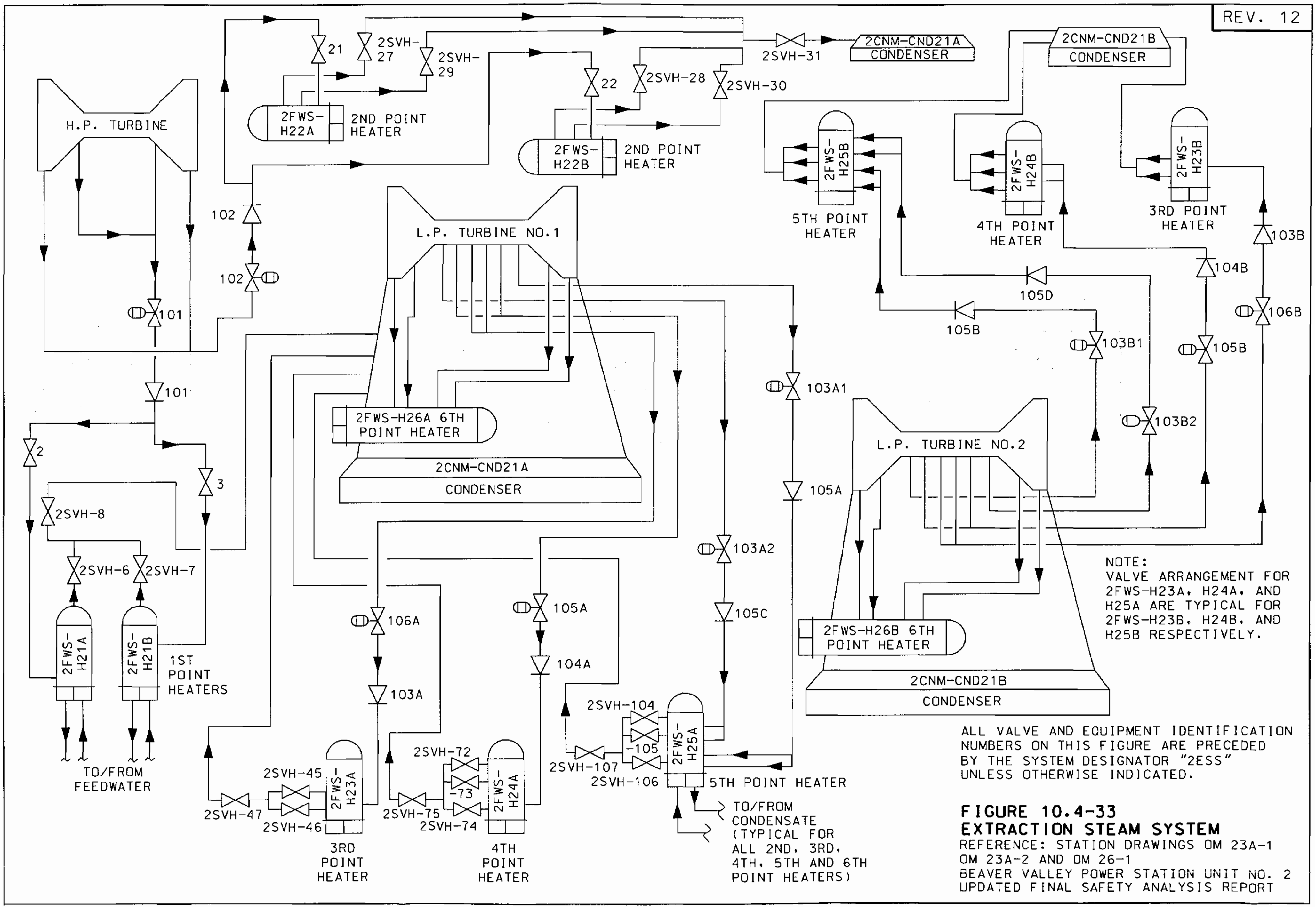


LEGEND

S/G	STEAM GENERATOR
DEMIN	DEMINERALIZED
RECIRC	RECIRCULATION

ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2FWE" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-24
AUXILIARY FEEDWATER SYSTEM
REFERENCE: STATION DRAWING OM 24-3
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTE:
VALVE ARRANGEMENT FOR 2FWS-H23A, H24A, AND H25A ARE TYPICAL FOR 2FWS-H23B, H24B, AND H25B RESPECTIVELY.

ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2ESS" UNLESS OTHERWISE INDICATED.

FIGURE 10.4-33
EXTRACTION STEAM SYSTEM
REFERENCE: STATION DRAWINGS OM 23A-1 OM 23A-2 AND OM 26-1
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

APPENDIX 10A

AUXILIARY FEEDWATER SYSTEM

SIMPLIFIED RELIABILITY ANALYSIS

NOTE: UFSAR Appendix 10A is for Historical Information only, and should not be used for plant-specific PRA Risk Determination.

CHAPTER 10A

AUXILIARY FEEDWATER SYSTEM SIMPLIFIED RELIABILITY ANALYSIS

TABLE OF CONTENTS

APPENDIX 10A

LIST OF FIGURES

10A AUXILIARY FEEDWATER SYSTEM SIMPLIFIED RELIABILITY ANALYSIS

10A.1 Unavailability Evaluation

A simplified reliability analysis was performed on the auxiliary feedwater system (AFWS) to determine the potential for system failure and to meet the intent of NUREG-0737 (USNRC 1980), Action Item II.E.1.1. This analysis was performed for the loss of main feedwater transient conditions, both with and without offsite power available.

10A.2 Summary of Findings

The analysis of the AFWS showed the system to be very reliable. An overall system unavailability was determined from common cause failures, independent human errors, hardware failures, and test and maintenance errors. Figures 10A-1 and 10A-2 show the simplified unavailability models for the Beaver Valley Power Station - Unit 2 (BVPS-2) AFWS. For the loss of main feedwater transient with offsite power available, the calculated overall system unavailability was 8.70×10^{-6}. For the transient where offsite power is not available, the calculated overall system unavailability was 9.00×10^{-6}. The slight increase in the unavailability of the system for the latter transient condition is a result of including the unavailability of the emergency diesel generator power sources in the hardware failures unavailability contribution.

10A.3 Methods and Assumptions Used

Two of the unavailability values used in the calculations for BVPS-2 were taken from the Zion Units 1 and 2 probabilistic Safety Study (ZPSS) (U.S. Nuclear Regulatory Commission 1981) that was performed on their AFWS. These were values for independent human errors and test and maintenance errors. Although the designs of the Zion units and BVPS-2 AFWSS are not identical, the unavailability values for these two failure contributors were assumed to be similar. The unavailability value for common cause failures is also an assumed value.

Fault tree logic technique (Sections 1.7 and 7.3.2) were used to determine the unavailability due to hardware failures. These fault trees are presented as FTSK-5-13M-A through FTSK-5-13M-AG. The fault trees were developed based on the following considerations and assumptions:

1. Electrical portions of the components in the fault trees are shown as single components. Since only one fault tree was used for both transients, for the transient that addresses the loss of offsite power the unavailability of the redundant emergency diesel generator power sources was included as directly causing the failure of the motor-driven auxiliary feedwater pump powered from that source. The

event blocks and logic gates for this portion of the loss are not shown on the fault trees, however.

2. The fault tree analysis is based on a system operating time of 24 hours being required to remove heat from the reactor coolant system.

3. The fault tree configuration reflects the availability of backup water sources. Therefore, a rupture of the primary plant demineralized water storage tank (PPDWST) or a piping failure between the PPDWST and any auxiliary feedwater pump has not been configured into the fault tree as causing the top event directly. This consideration requires the level in the PPDWST be monitored during system operation to allow sufficient time to align the backup water sources before the PPDWST supply, described in Section 10.4.9, is depleted.

   The backup water sources from the 600,000 gallon demineralized water storage tank and the service water system are described in Section 10.4.9. This fault tree configuration is believed to be representative of the actual mode of operation following a loss of feedwater transient condition.

4. The fault tree configuration is also based on system design features, such as the missile-protected PPDWST structure, the redundant power sources to the motor-driven auxiliary feedwater pumps, the location of these pumps in separate cubicles, and the seismic design of the safeguards building that these pumps are housed in.

5. In support of this evaluation, a separate study which showed the development of simplified event sequence diagrams that reflects the system operation was used.

10A.4 Single Failure Analysis

Based on the fault trees, a single failure analysis was performed using the SWEC CS-007 (Stone & Webster Engineering Corporation 1981) computer program. This program also generated the failure modes and effects analysis (FMEA) that describes the failure mode of each component and its effect on the system, including potential single failures. The FMEA is presented as FMEA-15-13M.

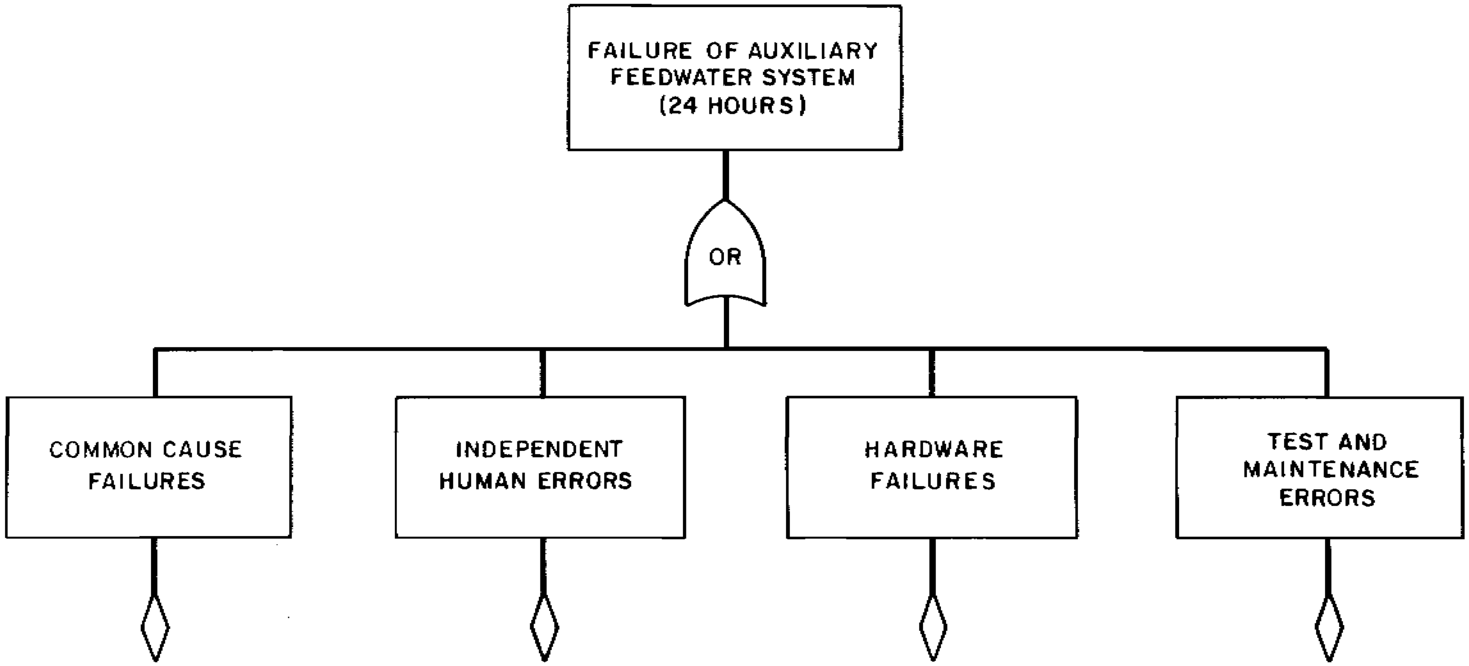
One source of a potential single failure was identified in the FMEA. This single failure would result from a rupture of the piping between the check valves downstream of each flow control valve and the cavitating venturi in the associated header. A rupture in the piping here could cause flow to all steam generators to be decreased. The control room operators would be alerted to this event by alarms and indications from the redundant flow transmitters in each header, and they could isolate the pipe rupture by closing the appropriate flow control valve. Flow would then be restored through the unaffected headers to meet the design requirements of the system.

10A.5 References for Appendix 10A

Stone & Webster Engineering Corporation 1981. Fault Tree Analysis Computer Program. SWEC CS-007.

U.S. Nuclear Regulatory Commission 1980. Clarification of TMI Action Plan Requirements. NUREG-0737.

U.S. Nuclear Regulatory Commission 1981. Zion Units 1 and 2 Probabilistic Safety Study, Volume 3, Section 1.5.2.3.9. Docket Nos. 50-295 and 50-304.

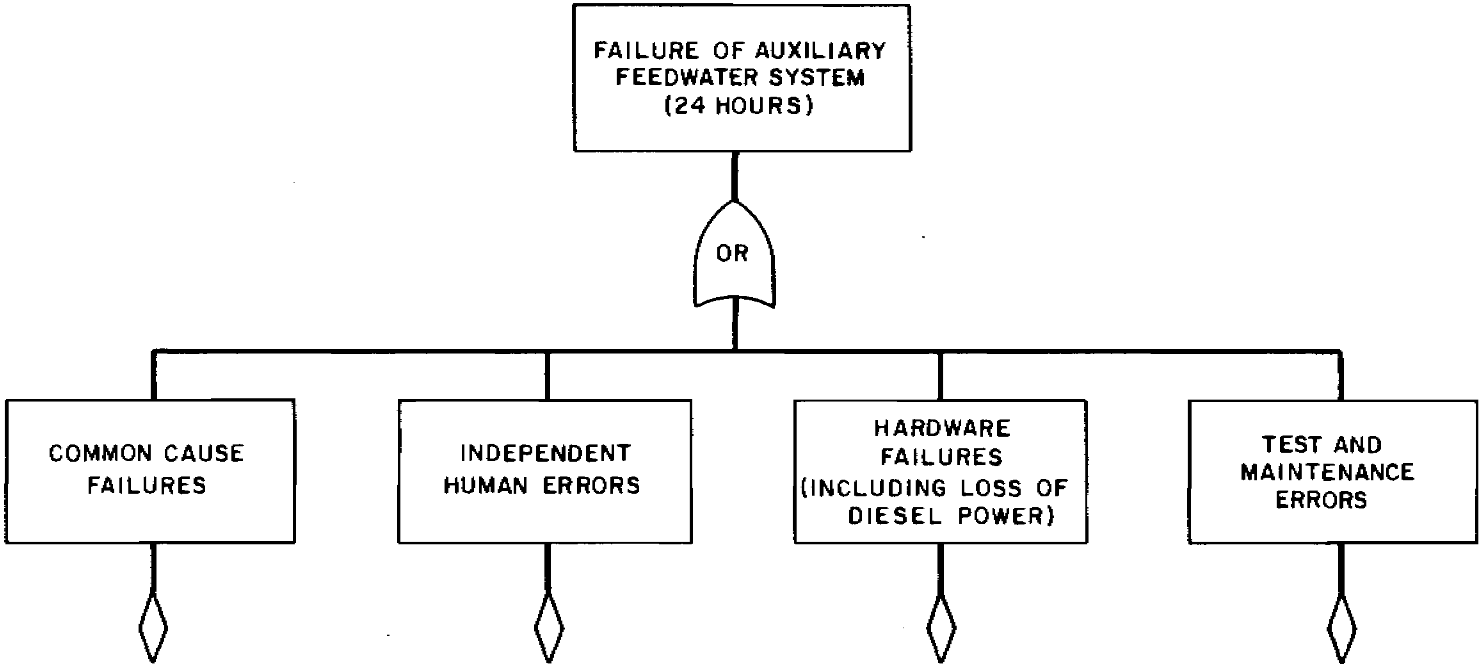


FAILURES	AVAILABILITY (A)	UNAVAILABILITY (Q)
COMMON CAUSE FAILURES	.9999990	1.00×10^{-6}
INDEPENDENT HUMAN ERRORS	.9999997	3.54×10^{-7} *
HARDWARE FAILURES	.9999958	4.21×10^{-6}
TEST AND MAINTENANCE ERRORS	.9999968	3.24×10^{-6} **
OVERALL SYSTEM	.9999913	8.70×10^{-6}

* ZPSS TABLE 1.5.2.3.9-7G

** ZPSS TABLE 1.5.2.3.9-7D

FIGURE 10A-1
AUXILIARY FEEDWATER SYSTEM
AVAILABILITY AND UNAVAILABILITY
(WITH OFFSITE POWER)
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



FAILURES	AVAILABILITY (A)	UNAVAILABILITY (Q)
COMMON CAUSE FAILURES	.9999990	1.00×10^{-6}
INDEPENDENT HUMAN ERRORS	.9999997	3.54×10^{-7} *
HARDWARE FAILURES (INCL. LOSS OF DIESELS)	.9999955	4.52×10^{-6}
TEST AND MAINTENANCE ERRORS	.9999968	3.24×10^{-6} **
OVERALL SYSTEM	.9999910	9.00×10^{-6}

FIGURE 10A-2
AUXILIARY FEEDWATER SYSTEM
AVAILABILITY AND UNAVAILABILITY
(WITHOUT OFFSITE POWER)
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

* ZPSS TABLE 1.5.2.3.9-7G
** ZPSS TABLE 1.5.2.3.9-7D

FTSK	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-A 5-13M-C	F00141A1	PIPE BREAK FROM 2FWE*FE101A TO SG21A	ANNUNCIATED IN CONTROL ROOM	FAILURE OF AUX FEED TO SG21A	
5-13M-A 5-13M-D	F00241A1	PIPE BREAK FROM 2FWE*FE101B TO SG21B	ANNUNCIATED IN CONTROL ROOM	FAILURE OF AUX FEED TO SG21B	
5-13M-A 5-13M-C	F00341A1	PIPE BREAK FROM 2FWE*FE101C TO SG21C	ANNUNCIATED IN CONTROL ROOM	FAILURE OF AUX FEED TO SG21C	
5-13M-B	F00441A1	COMMON PATH PIPE BREAK FROM 2FWE*V233 & V234 TO FE101A	ANNUNCIATED IN CONTROL ROOM	FAILURE OF AUXILIARY FEED	***SINGLE FAILURE*** PIPEBREAK ASSUMED IN PIPEBREAK EXCLUSION AREA
5-13M-B	F00541A1	COMMON PATH PIPE BREAK FROM 2FWE*V237 & V238 TO FE101C	ANNUNCIATED IN CONTROL ROOM	FAILURE OF AUXILIARY FEED	***SINGLE FAILURE*** PIPEBREAK ASSUMED IN PIPEBREAK EXCLUSION AREA
5-13M-B	F00641A1	COMMON PATH PIPE BREAK FROM 2FWE*V235 & V236 TO FE101B	ANNUNCIATED IN CONTROL ROOM	FAILURE OF AUXILIARY FEED	***SINGLE FAILURE*** PIPEBREAK ASSUMED IN PIPEBREAK EXCLUSION AREA
5-13M-E 5-13M-F 5-13M-K	F00741A1	RECIRC LINE PIPE BREAK FROM FCV122 TO TK210	ANNUNCIATED IN CONTROL ROOM	AUX FEED PATH A TO SG21A FAILS	
5-13M-E 5-13M-F 5-13M-K	F00841A1	RECIRC LINE PIPE BREAK FROM FCV122 TO TK210	ANNUNCIATED IN CONTROL ROOM	AUX FEED PATH A TO SG21A FAILS	
5-13M-E	F00941A2	PIPE BREAK FROM 2FWE*V233 TO FCV123A OR FCV122	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH A TO SG21A FAILS	
5-13M-E	F01041A2	2FWE*HCV100E CLOSED (ELEC-CONTL) FAILURE	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH A TO SG21A FAILS	
5-13M-E	F01141A3	2FWE*HCV100E CLOSED (MECH FAILURE)	PERIODIC TEST	AUX FEED PATH A TO SG21A FAILS	

FTSM	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-E	F01241A6	2FWE*HCV100E CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH A TO SG21A FAILS	
5-13M-E	F01341A3	2FWE*V233 FAILS (MECHANICAL)	PERIODIC TEST	NONE	
5-13M-L 5-13M-M 5-13M-S	F01441A3	2FWE*FCV123A CLOSED	PERIODIC TEST	NO FLOW PATH A TO SG21A FROM 2FWE*P23A	
5-13M-L 5-13M-M 5-13M-S	F01541A2	PIPE BREAK FROM 2FWE*P23A TO 2FWE*FCV123A	INDICATING LIGHT IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P23A	
5-13M-AC	F01641A1	2FWE*P23A FAILS (ELEC-CONTL)	ANNUNCIATED IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P23A	
5-13M-AC	F01741A3	2FWE*P23A FAILS (MECHANICAL)	PERIODIC TEST	NO FLOW PATH A TO SG21A FROM 2FWE*P23A	
5-13M-S	F01841A6	2FWE*V216 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	NO FLOW PATH A TO SG21A FROM 2FWE*P23A	
5-13M-S	F01941A3	2FWE*V216 CLOSED (MECH FAILS)	PERIODIC TEST	NO FLOW PATH A TO SG21A FROM 2FWE*P23A	
5-13M-W 5-13M-X 5-13M-AH	F02041A2	PIPE BREAK FROM TK210 TO 2FWE*P26	INDICATING LIGHT IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-X	F02141A6	2FWE*V212 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-X	F02241A3	2FWE*V212 CLOSED (MECH FAILS)	PERIODIC TEST	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AH	F02341A2	PIPE BREAK FROM TK210 TO 2FWE*P23A	INDICATING LIGHT IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AH	F02441A2	PIPE BREAK FROM TK210 TO 2FWE*P23B	INDICATING LIGHT IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AH	F02541A2	PIPE BREAK FROM TK210 TO 2FWE*P22	INDICATING LIGHT IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AH	F02641A1	2FWE*TK210 RUPTURE	ANNUNCIATED IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	

FTSK	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-AH	F02741A3	2FWE*TK210 VENTS BLOCKED	PERIODIC TEST	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-X	F02841A6	2FWE*V34 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-X	F02941A3	2FWE*V34 CLOSED (MECH FAILS)	PERIODIC TEST	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-P 5-13M-Q 5-13M-R	F0304IA3	2FWE*FCV122 CLOSED	PERIODIC TEST	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-P 5-13M-Q 5-13M-R	F03141A2	PIPE BREAK FROM 2FWE*P22 TO 2FWE*FCV122	INDICATING LIGHT IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-AD	F03241A1	2FWE*P22 FAILS (ELEC-CONTL)	ANNUNCIATED IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-AD	F03341A1	2FWE*P22 FAILS (MECHANICAL)	ANNUNCIATED IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-R	F03441A6	2FWE*V47 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-R	F03541A3	2FWE*V47 CLOSED (MECH FAILS)	PERIODIC TEST	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-AH	F03841A6	2FWE*V42 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	NORMAL WATER SUPPLY TO 2FWE*P22 FAILS	
5-13M-AH	F03941A3	2FWE*V42 CLOSED (MECH FAILS)	PERIODIC TEST	NORMAL WATER SUPPLY TO 2FWE*P22 FAILS	
5-13M-AJ	F04041A6	2FWE*V211 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	NORMAL WATER SUPPLY TO 2FWE*P22 FAILS	
5-13M-AJ	F04141A3	2FWE*V211 CLOSED (MECH FAILS)	PERIODIC TEST	NORMAL WATER SUPPLY TO 2FWE*P22 FAILS	
5-13M-F	F04241A2	PIPE BREAK FROM 2FWE*V235 TO FCV123A OR FCV122	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH A TO SG21B FAILS	
5-13M-F	F04341A2	2FWE*HCV100C CLOSED (ELEC-CONTL) FAILURE	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH A TO SG21B FAILS	

FTSM	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-F	F04441A3	2FWE*HCV100C CLOSED (MECH FAILURE)	PERIODIC TEST	AUX FEED PATH A TO SG21B FAILS	
5-13M-F	F04541A6	2FWE*HCV100C CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH A TO SG21B FAILS	
5-13M-F	F04641A3	2FWE*V235 FAILS (MECH)	PERIODIC TEST	NONE	
5-13M-K 5-13M-N	F04941A2	PIPE BREAK FROM 2FWE*V237 TO FCV123A OR FCV122	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH A TO SG21C FAILS	
5-13M-K	F05041A2	2FWE*HCV100A CLOSED (ELEC-CONTL) FAILURE	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH A TO SG21C FAILS	
5-13M-K	F05141A3	2FWE*HCV100A CLOSED (MECH FAILURE)	PERIODIC TEST	AUX FEED PATH A TO SG21C FAILS	
5-13M-K	F05241A6	2FWE*HCV100A CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH A TO SG21C FAILS	
5-13M-N	F05341A3	2FWE*V237 FAILS (MECH)	PERIODIC TEST	NONE	
5-13M-H 5-13M-J 5-13M-G	F05441A1	RECIRC LINE PIPE BREAK FROM FCV123B TO TK210	ANNUNCIATED IN CONTROL ROOM	AUX FEED PATH B TO SG21A FAILS	
5-13M-H	F05541A2	PIPE BREAK FROM 2FWE*V234 TO 2FWE*FCV123B	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21A FAILS	
5-13M-H	F05641A2	2FWE*HCV100F CLOSED (ELEC-CONTL FAILURE)	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21A FAILS	
5-13M-H	F05741A3	2FWE*HCV100F CLOSED (MECH FAILURE)	PERIODIC TEST	AUX FEED PATH B TO SG21A FAILS	

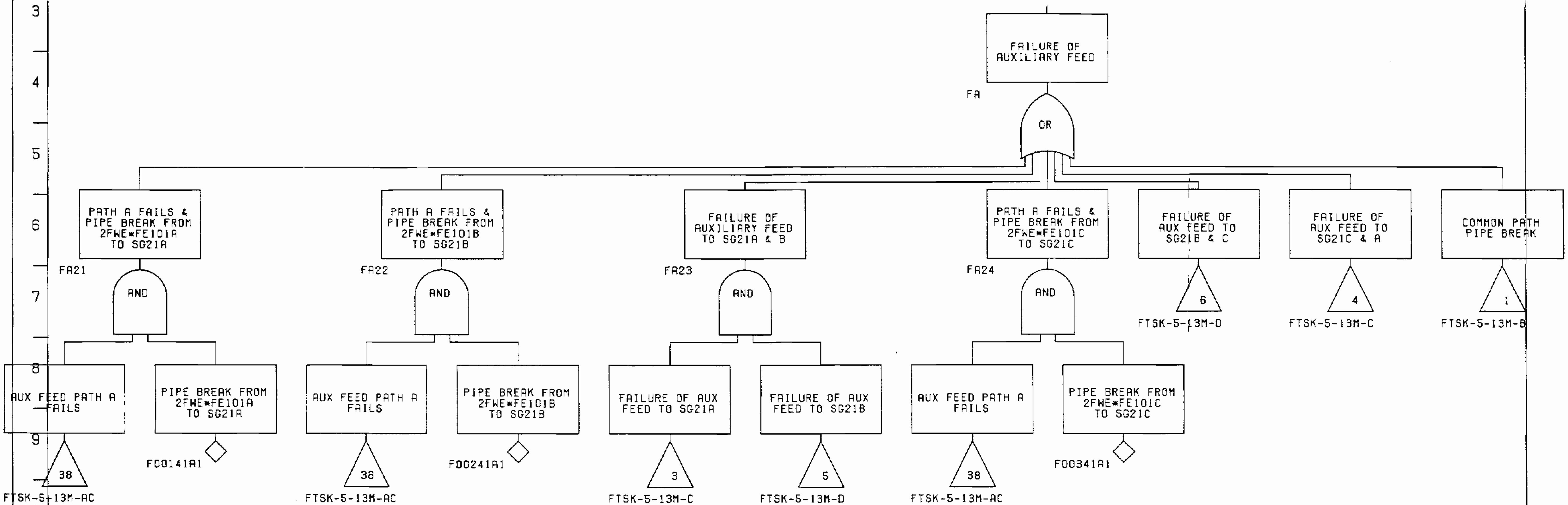
FTSK	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-H	F05841A6	2FWE*HCV100F CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH B TO SG21A FAILS	
5-13M-H	F05941A3	2FWE*V234 FAIL (MECHANICAL)	PERIODIC TEST	NONE	
5-13M-T 5-13M-U 5-13M-V	F06041A3	2FWE*FCV123B CLOSED	PERIODIC TEST	AUX FEED PATH B TO SG21A FAILS	
5-13M-T 5-13M-U 5-13M-V	F06141A2	PIPE BREAK FROM 2FWE*P23B TO 2FWE*FCV123B	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21A FAILS	
5-13M-V	F06241A1	2FWE*P23B FAILS (ELEC-CONTL)	ANNUNCIATED IN CONTROL ROOM	AUX FEED PATH B TO SG21A FAILS	
5-13M-V	F06341A3	2FWE*P23B FAILS (MECHANICAL)	PERIODIC TEST	AUX FEED PATH B TO SG21A FAILS	
5-13M-V	F06441A6	2FWE*V45 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH B TO SG21A FAILS	
5-13M-V	F06541A3	2FWE*V45 CLOSED (MECH FAILS)	PERIODIC TEST	AUX FEED PATH B TO SG21A FAILS	
5-13M-H	F06641A6	2FWE*V40 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	NORMAL WATER SUPPLY TO 2FWE*P2 FAILS	
5-13M-H	F06741A3	2FWE*V40 CLOSED (MECH FAILS)	PERIODIC TEST	NORMAL WATER SUPPLY TO 2FWE*P2 FAILS	
5-13M-H	F06841A6	2FWE*V35 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	NORMAL WATER SUPPLY TO 2FWE*P2 FAILS	
5-13M-H	F06941A3	2FWE*V35 CLOSED (MECH FAILS)	PERIODIC TEST	NORMAL WATER SUPPLY TO 2FWE*P2 FAILS	
5-13M-J	F07041A2	PIPE BREAK FROM 2FWE*V236 TO 2FWE*FCV123B	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21B FAILS	
5-13M-J	F07141A2	2FWE*HCV100D CLOSED (ELEC-CONTL) FAILURE	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21B FAILS	

FTSK	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-J	F07241A3	2FWE*HCV100D CLOSED (MECH FAILURE)	PERIODIC TEST	AUX FEED PATH B TO SG21B FAILS	
5-13M-J	F07341A6	2FWE*HCV100D CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH B TO SG21B FAILS	
5-13M-J	F07441A3	2FWE*V236 (MECH FAILS)	PERIODIC TEST	NONE	
5-13M-G	F07541A2	PIPE BREAK FROM 2FWE*V238 TO 2FWE*FCV123B	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21C FAILS	
5-13M-G	F07641A2	2FWE*HCV100B CLOSED ((ELEC-CONTL)FAILUR	INDICATING LIGHT IN CONTROL ROOM	AUX FEED PATH B TO SG21C FAILS	
5-13M-G	F07741A3	2FWE*HCV100B CLOSED (MECH FAILURE)	PERIODIC TEST	AUX FEED PATH B TO SG21C FAILS	
5-13M-G	F07841A6	2FWE*HCV100B CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	AUX FEED PATH B TO SG21C FAILS	
5-13M-G	F07941A3	2FWE*V238 (MECH FAILS)	PERIODIC TEST	NONE	
5-13M-AE	F08041A2	2MSS*SOV105A (ELEC-CONTL) FAILS	INDICATING LIGHT IN CONTROL ROOM	MAIN STEAM PATH A FAILS	
5-13M-AE	F08141A3	2MSS*SOV105A (MECHANICAL) FAILS	PERIODIC TEST	MAIN STEAM PATH A FAILS	
5-13M-AE	F08241A2	2MSS*SOV105D (ELEC-CONTL) FAILS	INDICATING LIGHT IN CONTROL ROOM	MAIN STEAM PATH A FAILS	
5-13M-AE	F08341A3	2MSS*SOV105D (MECHANICAL) FAILS	PERIODIC TEST	MAIN STEAM PATH A FAILS	
5-13M-AD	F08441A1	PIPE BREAK FROM 2MSS*V97 TO TURBINE	ANNUNCIATED IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P22	

FTSM	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-AD	F08541A1	PIPE BREAK FROM 2MSS*V81 TO TURBINE	ANNUNCIATED IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-AD	F08641A1	PIPE BREAK FROM 2MSS*V82 TO TURBINE	ANNUNCIATED IN CONTROL ROOM	NO FLOW PATH A TO SG21A FROM 2FWE*P22	
5-13M-AE	F08741A1	2RCS*SG21A FAILS	ANNUNCIATED IN CONTROL ROOM	MAIN STEAM PATH A FAILS	
5-13M-AE	F08841A1	PIPE BREAK FROM 2RCS*SG21A TO 2MSS*V82	ANNUNCIATED IN CONTROL ROOM	MAIN STEAM PATH A FAILS	
5-13M-AE	F08941A2	2MSS*V87 CLOSED (MECH FAILS)	INDICATING LIGHT IN CONTROL ROOM	MAIN STEAM PATH A FAILS	
5-13M-AE	F09041A6	2MSS*V87 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	MAIN STEAM PATH A FAILS	
5-13M-AG	F09141A1	PIPE BREAK FROM 2RCS*SG21B TO 2MSS*V88	ANNUNCIATED IN CONTROL ROOM	MAIN STEAM PATH B FAILS	
5-13M-AG	F09241A2	PIPE BREAK FROM 2MSS*V88 2MSS*V81	INDICATING LIGHT IN CONTROL ROOM	MAIN STEAM PATH B FAILS	
5-13M-AG	F09341A6	2MSS*V88 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	MAIN STEAM PATH B FAILS	
5-13M-AG	F09441A3	2MSS*SOV105B CLOSED	PERIODIC TEST	MAIN STEAM PATH B FAILS	
5-13M-AG	F09541A3	2MSS*SOV105E CLOSED	PERIODIC TEST	MAIN STEAM PATH B FAILS	
5-13M-AG	F09641A1	2RCS*SG21B FAILS	ANNUNCIATED IN CONTROL ROOM	MAIN STEAM PATH B FAILS	
5-13M-AF	F09741A1	PIPE BREAK FROM 2RCS*SG21C TO 2MSS*V80	ANNUNCIATED IN CONTROL ROOM	MAIN STEAM PATH C FAILS	
5-13M-AF	F09841A2	PIPE BREAK FROM 2MSS*V80 TO 2MSS*V97	INDICATING LIGHT IN CONTROL ROOM	MAIN STEAM PATH C FAILS	
5-13M-AF	F09941A6	2MSS*V80 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	MAIN STEAM PATH C FAILS	

FTSK	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-AF	F10041A3	2MSS*SOV105C CLOSED	PERIODIC TEST	MAIN STEAM PATH C FAILS	
5-13M-AF	F10141A3	2MSS*SOV105F CLOSED	PERIODIC TEST	MAIN STEAM PATH C FAILS	
5-13M-AF	F10241A1	2RCS*SG21C FAILS	ANNUNCIATED IN CONTROL ROOM	MAIN STEAM PATH C FAILS	
5-13M-AC	F10341A3	2FWE*FCV123A OPEN	PERIODIC TEST	NONE	
5-13M-AC	F10441A3	2FWE*FCV122 OPEN	PERIODIC TEST	NONE	
5-13M-Z	F10541A2	PIPE BREAK FROM 2FWE*P23A TO SERVICE WATER	INDICATING LIGHT IN CONTROL ROOM	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-Z 5-13M-Y 5-13M-AA	F10641A2	NO WATER AVAILABLE	INDICATING LIGHT IN CONTROL ROOM	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-AB	F10741A2	PIPE BREAK BTWN 2FWE*TK210 & 2WTD*TK23	INDICATING LIGHT IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AB	F10841A1	2WTD*TK23 FAILS	ANNUNCIATED IN CONTROL ROOM	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AA	F10941A6	2FWE*V214 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-AA	F11041A3	2FWE*V214 CLOSED (MECH FAILS)	PERIODIC TEST	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-Z	F11141A6	2FWE*V213 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-Z	F11241A3	2FWE*V213 CLOSED (MECH FAILS)	PERIODIC TEST	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-AB	F11341A6	2FWE*V351 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AB	F11441A3	2FWE*V351 CLOSED (MECH FAILS)	PERIODIC TEST	DEMINERALIZED WATER SUPPLY NOT AVAILABLE	
5-13M-AA	F11541A2	PIPE BREAK FROM 2FWE*P22 TO SERVICE WATER	INDICATING LIGHT IN CONTROL ROOM	SERVICE WATER SUPPLY NOT AVAILABLE	

FTSK	COMPONENT IDENTIFIER	COMPONENT AND FAILURE MODE	METHOD OF FAILURE DETECTION	EFFECT ON SYSTEM	OTHER REMARKS
5-13M-AA	F11641A6	2FWE*V41 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-AA	F11741A3	2FWE*V41 CLOSED (MECH FAILS)	PERIODIC TEST	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-Y	F11841A1	PIPE BREAK FROM 2FWE*P23B TO SERVICE WATER	ANNUNCIATED IN CONTROL ROOM	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-Y	F11941A6	2FWE*V39 CLOSED (HUMAN ERROR)	PERIODIC INSPECTION	SERVICE WATER SUPPLY NOT AVAILABLE	
5-13M-Y	F12041A3	2FWE*V39 CLOSED (MECH FAILS)	PERIODIC TEST	SERVICE WATER SUPPLY NOT AVAILABLE	



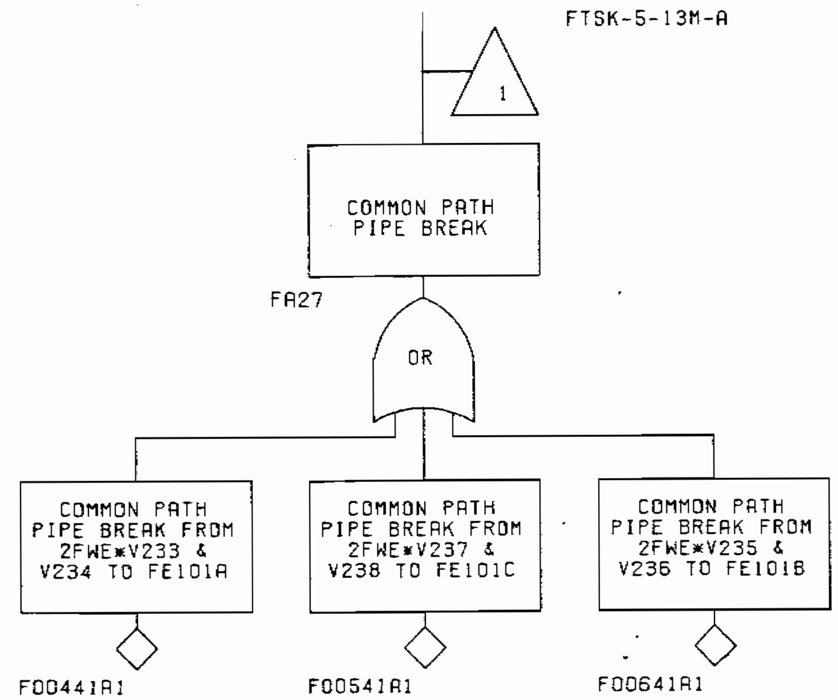
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-A



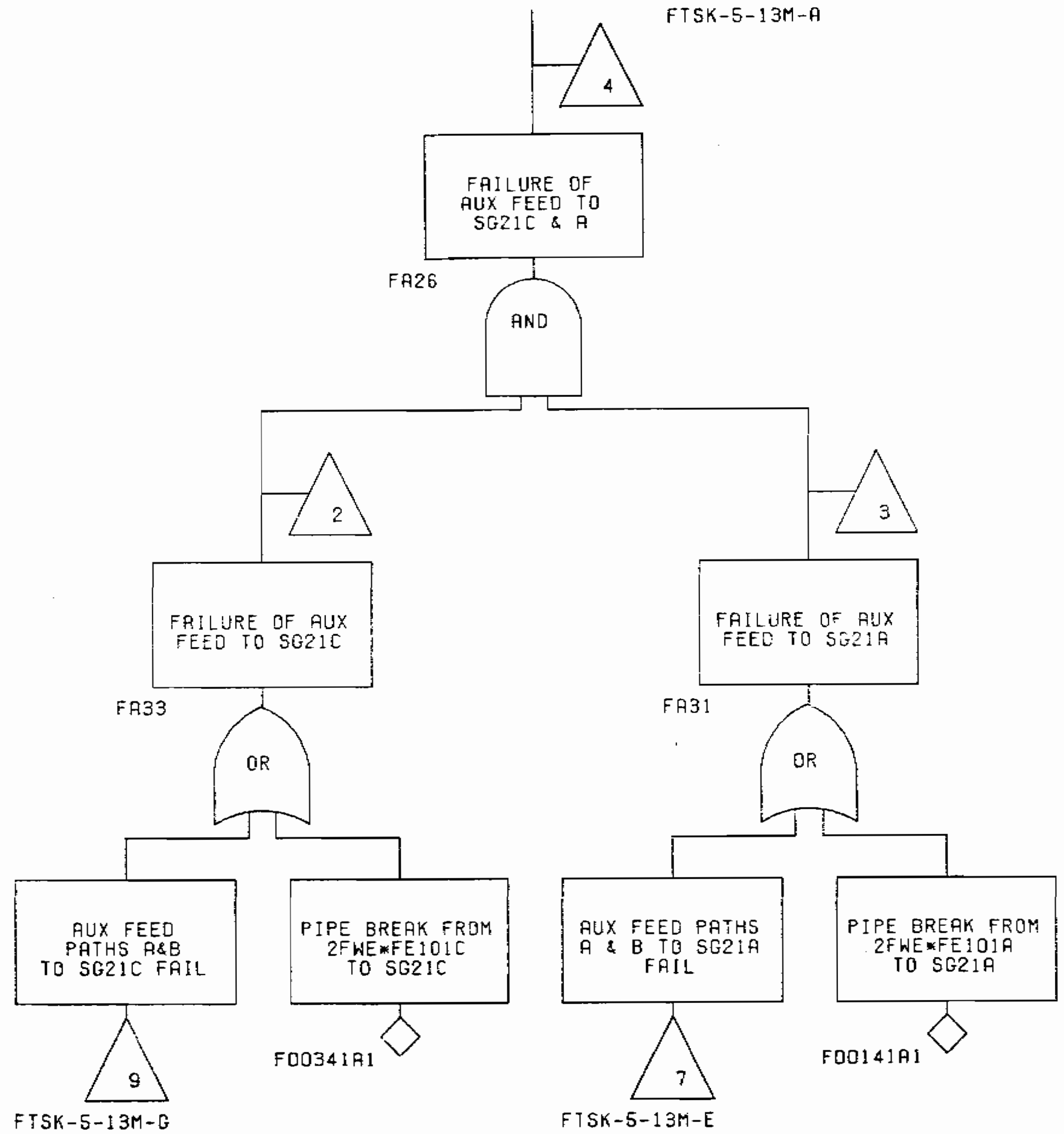
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-B



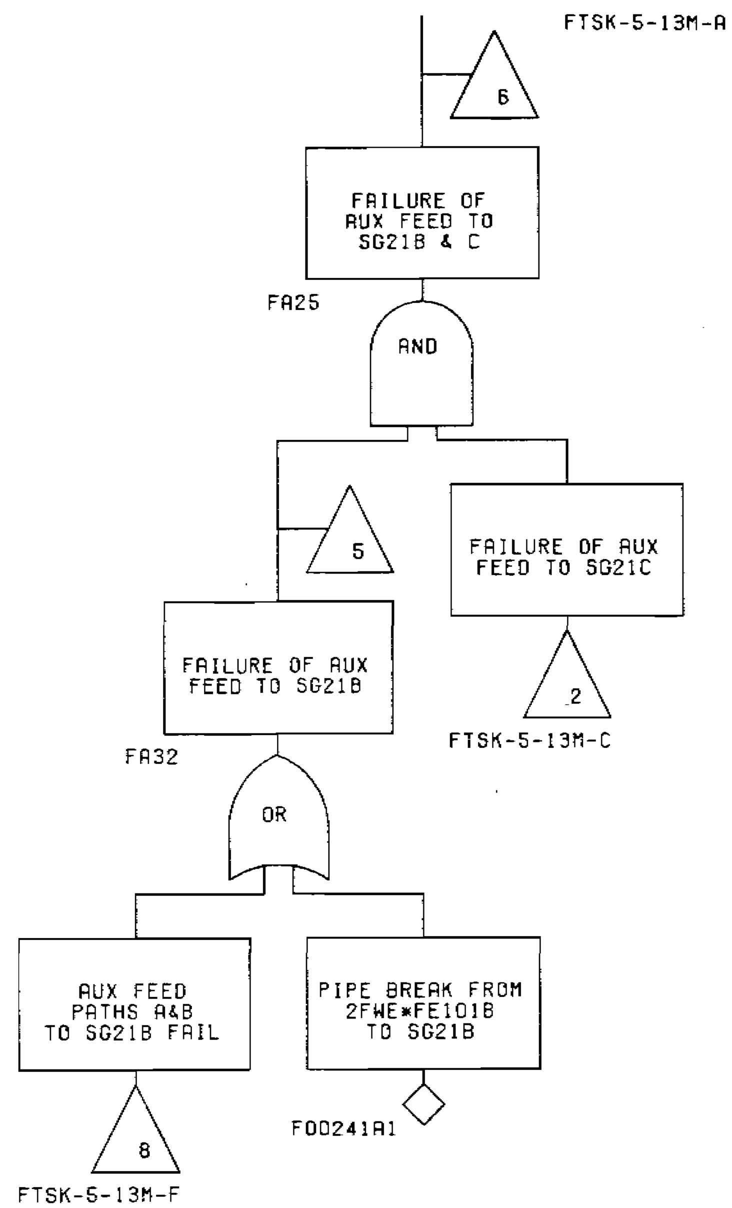
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-C



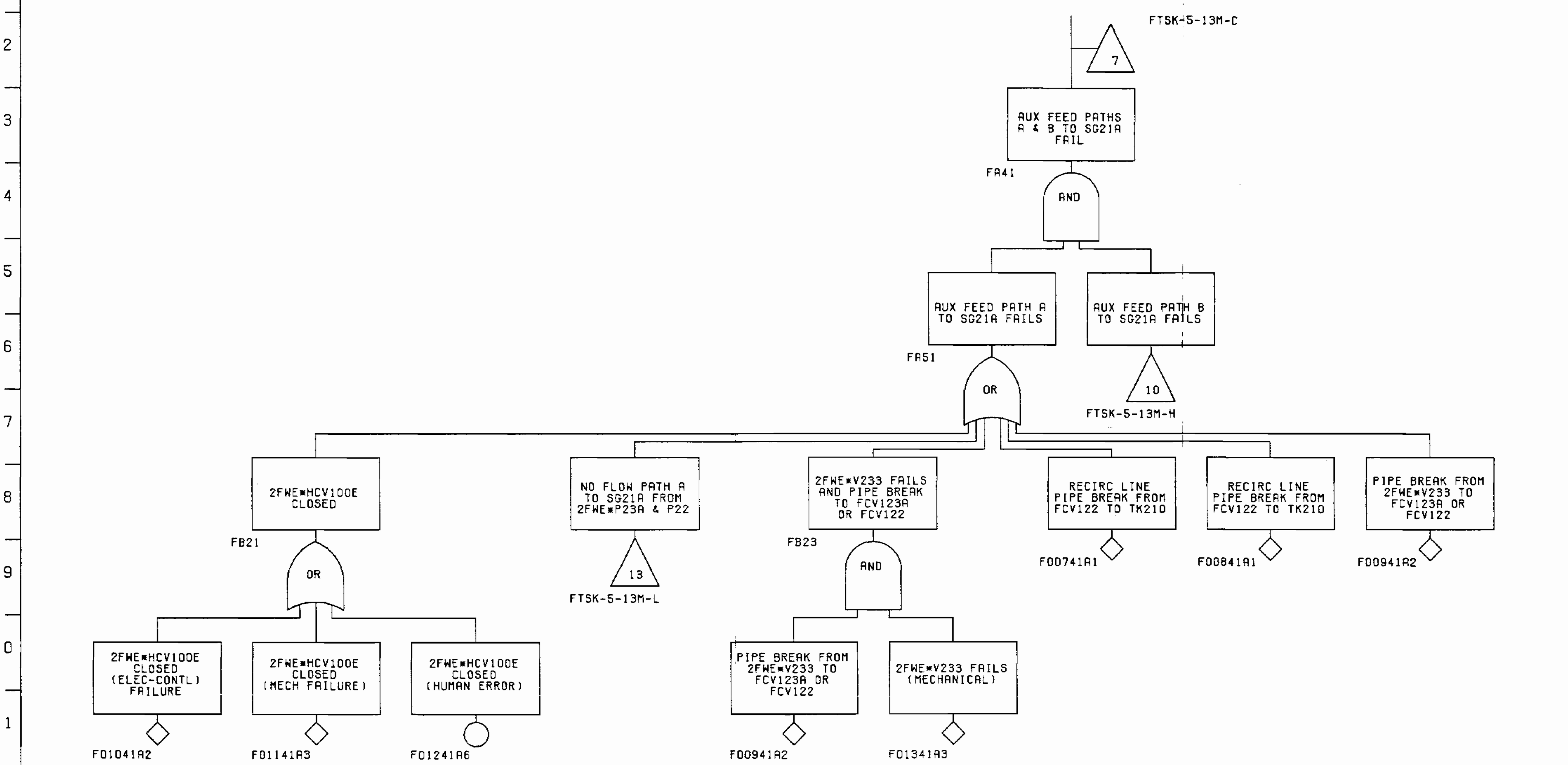
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-D



FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

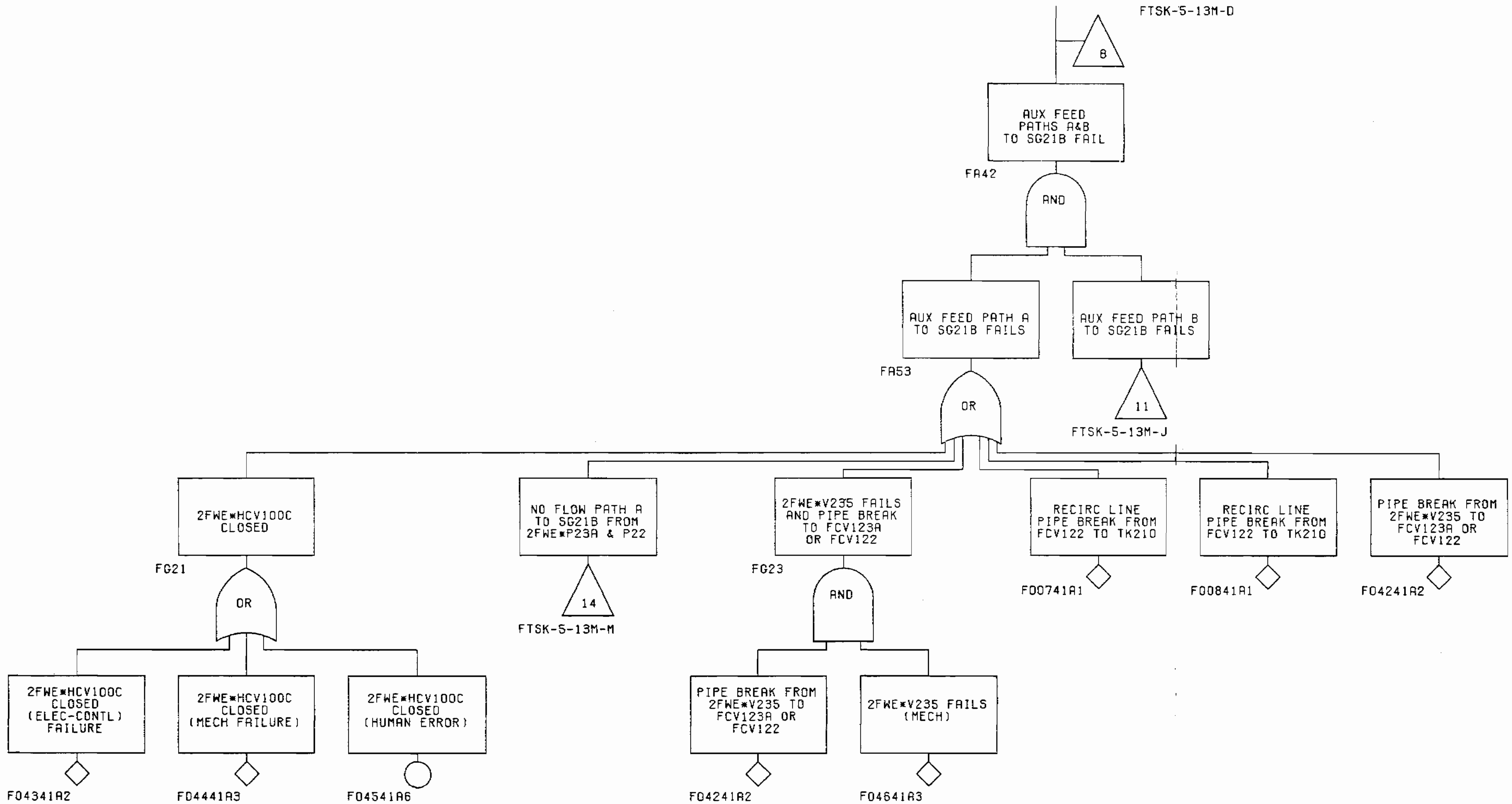
STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-E

C							
P	7	6	5	4	3	2	1
E							

1 2 3 4 5 6 7 8 9 10 11 12 13

A B C D E F G H I J K L M N O P Q R S T



FAULT TREE DIAGRAM

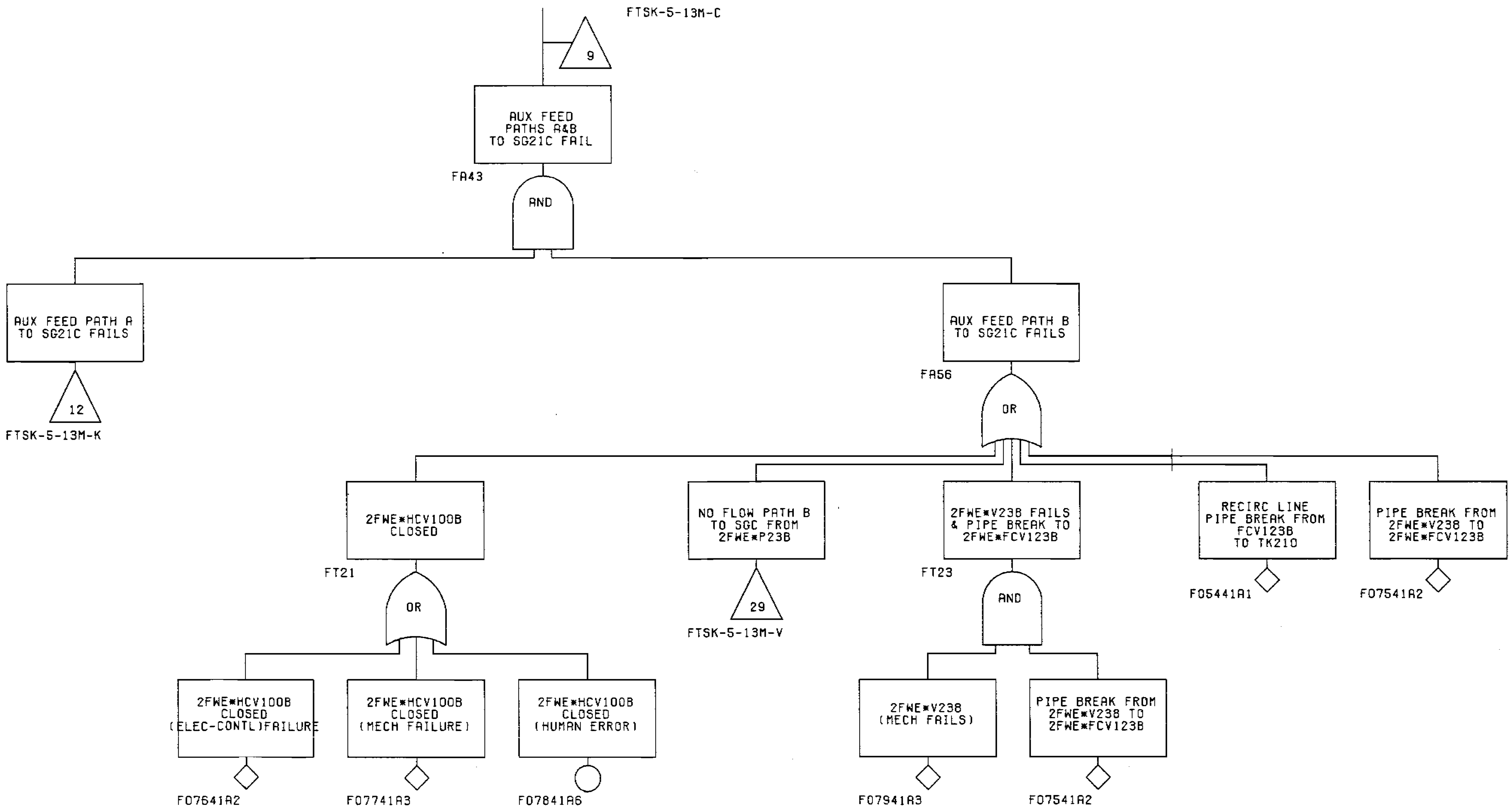
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-F

C							
P	7	6	5	4	3	2	1
E							



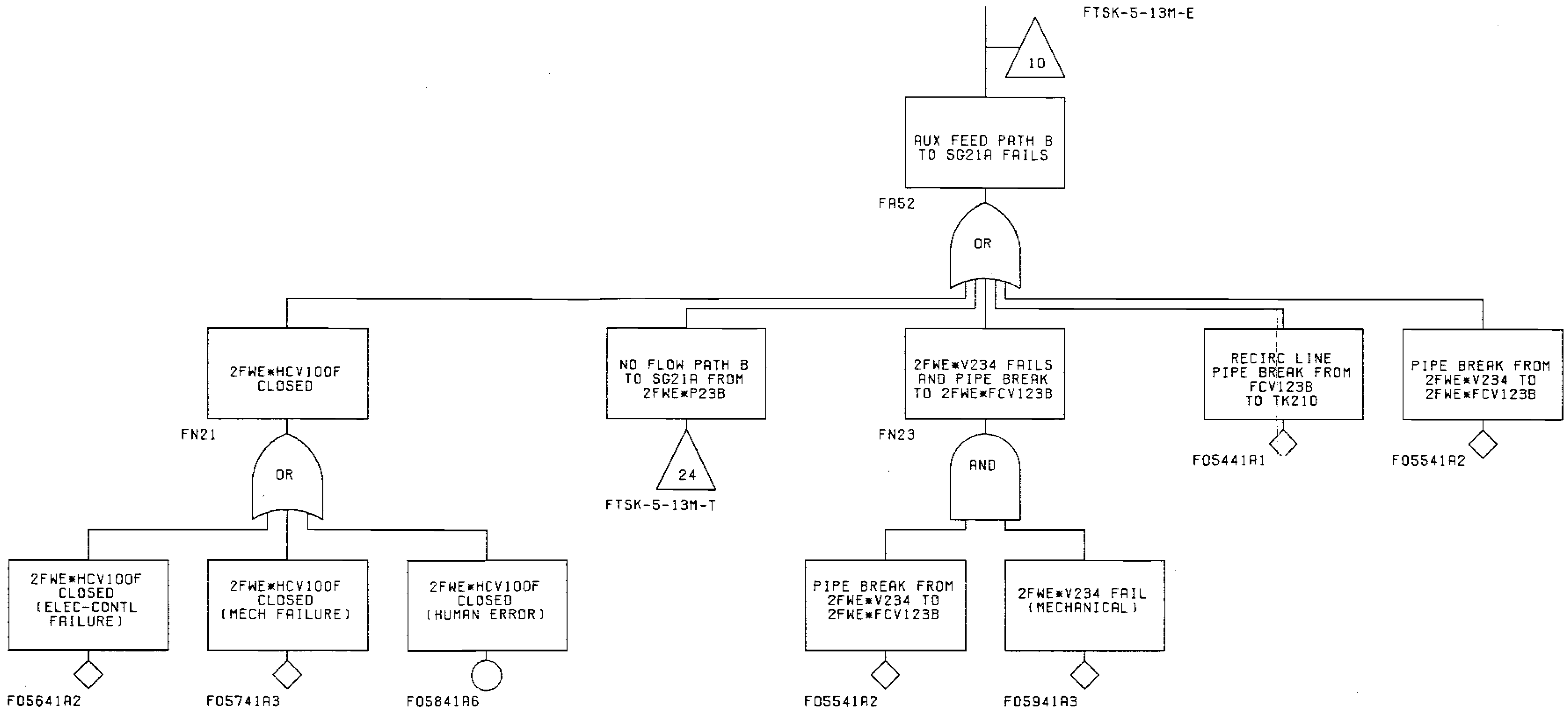
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-G



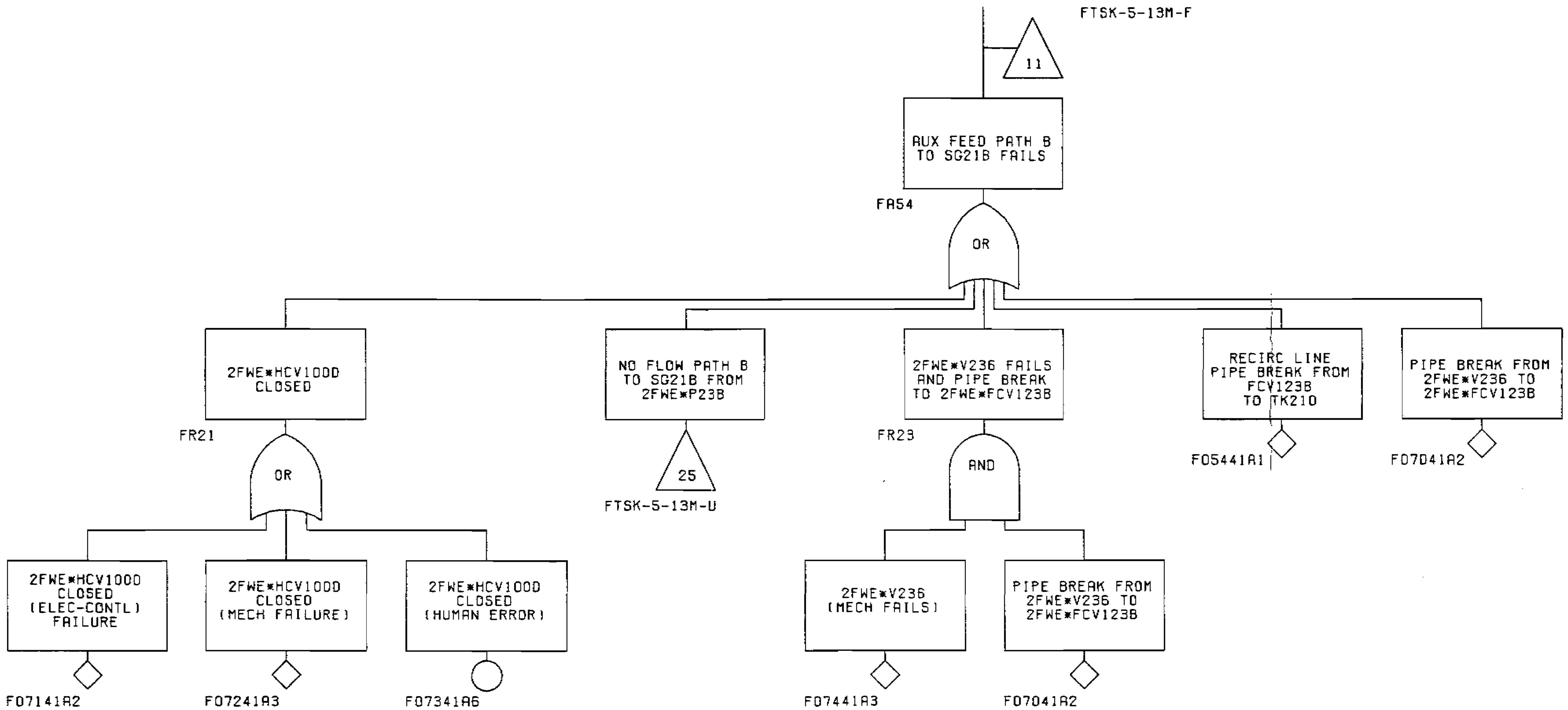
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-H



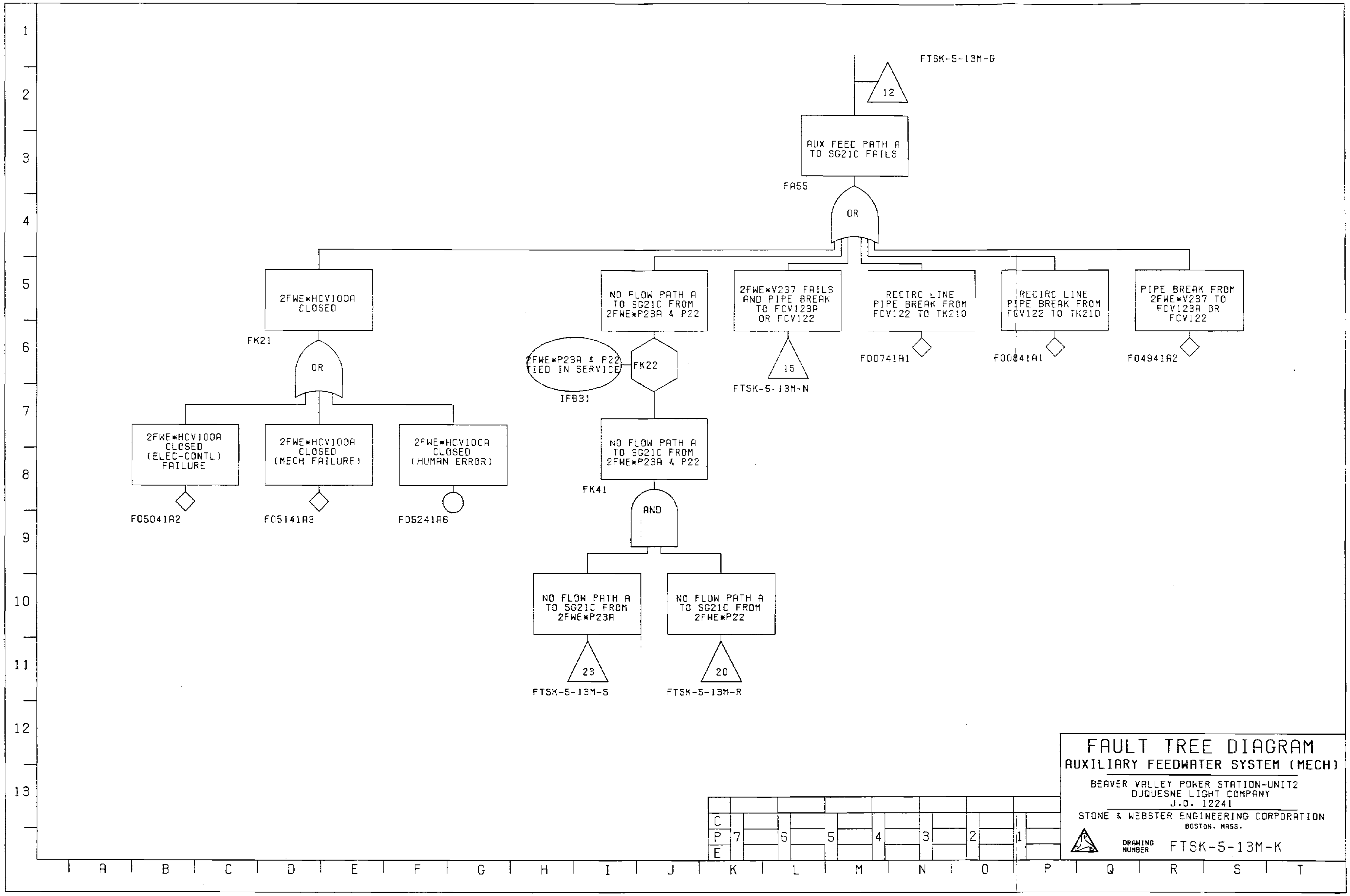
FAULT TREE DIAGRAM

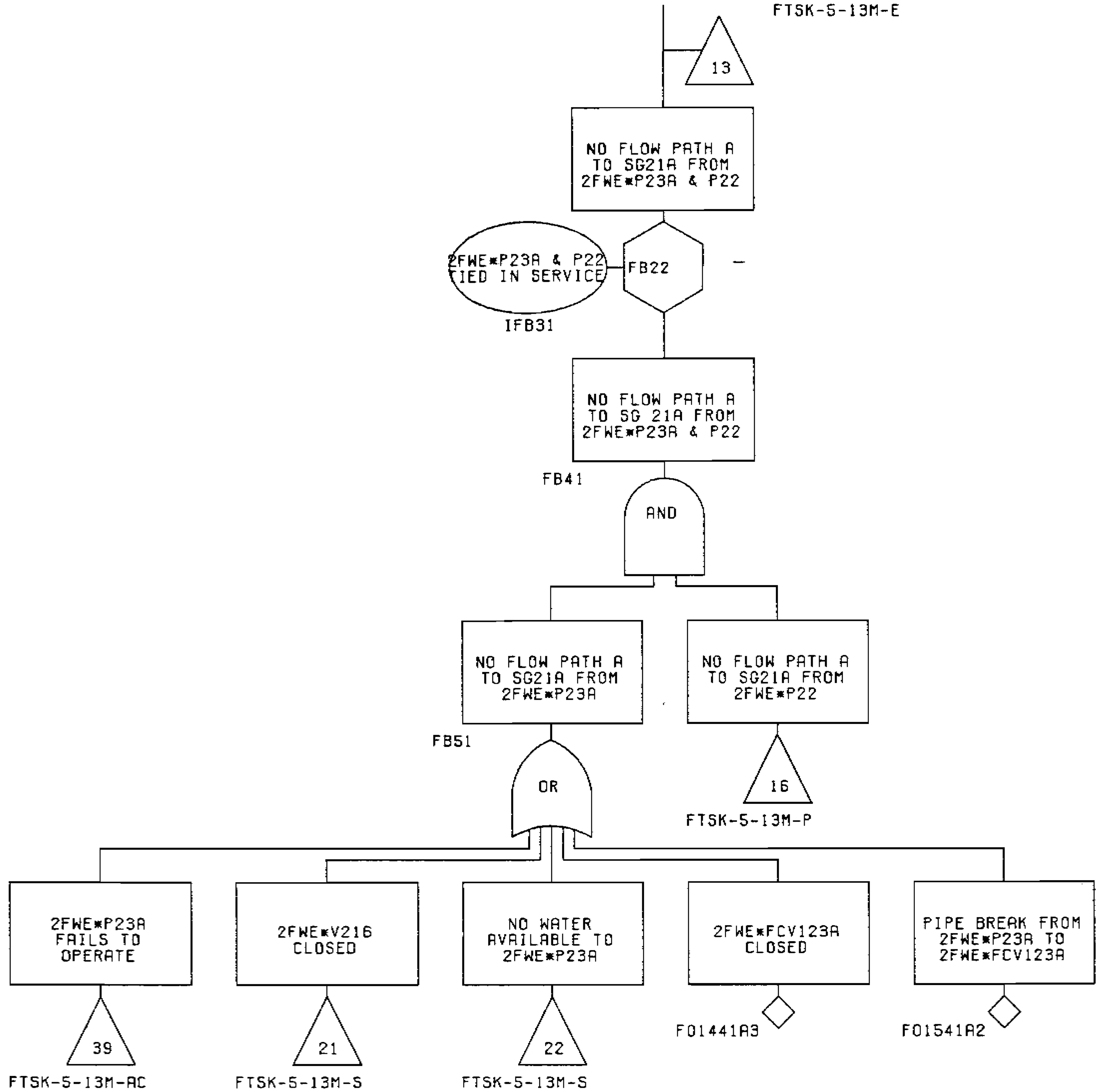
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-J


FTSK-5-13M-G
12
AUX FEED PATH A TO SG21C FAILS
FA55
OR
2FWE*HCV100A CLOSED
FK21
OR
2FWE*HCV100A CLOSED (ELEC-CONTL) FAILURE
F05041A2
2FWE*HCV100A CLOSED (MECH FAILURE)
F05141A3
2FWE*HCV100A CLOSED (HUMAN ERROR)
F05241A6
NO FLOW PATH A TO SG21C FROM 2FWE*P23A & P22
2FWE*P23A & P22 TIED IN SERVICE
IFB31
FK22
NO FLOW PATH A TO SG21C FROM 2FWE*P23A & P22
FK41
AND
NO FLOW PATH A TO SG21C FROM 2FWE*P23A
23
FTSK-5-13M-S
NO FLOW PATH A TO SG21C FROM 2FWE*P22
20
FTSK-5-13M-R
2FWE*V237 FAILS AND PIPE BREAK TO FCV123A OR FCV122
15
FTSK-5-13M-N
RECIRC LINE PIPE BREAK FROM FCV122 TO TK210
F00741A1
RECIRC LINE PIPE BREAK FROM FCV122 TO TK210
F00841A1
PIPE BREAK FROM 2FWE*V237 TO FCV123A OR FCV122
F04941A2
FAULT TREE DIAGRAM
AUXILIARY FEEDWATER SYSTEM (MECH)
BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241
STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.
DRAWING NUMBER
FTSK-5-13M-K



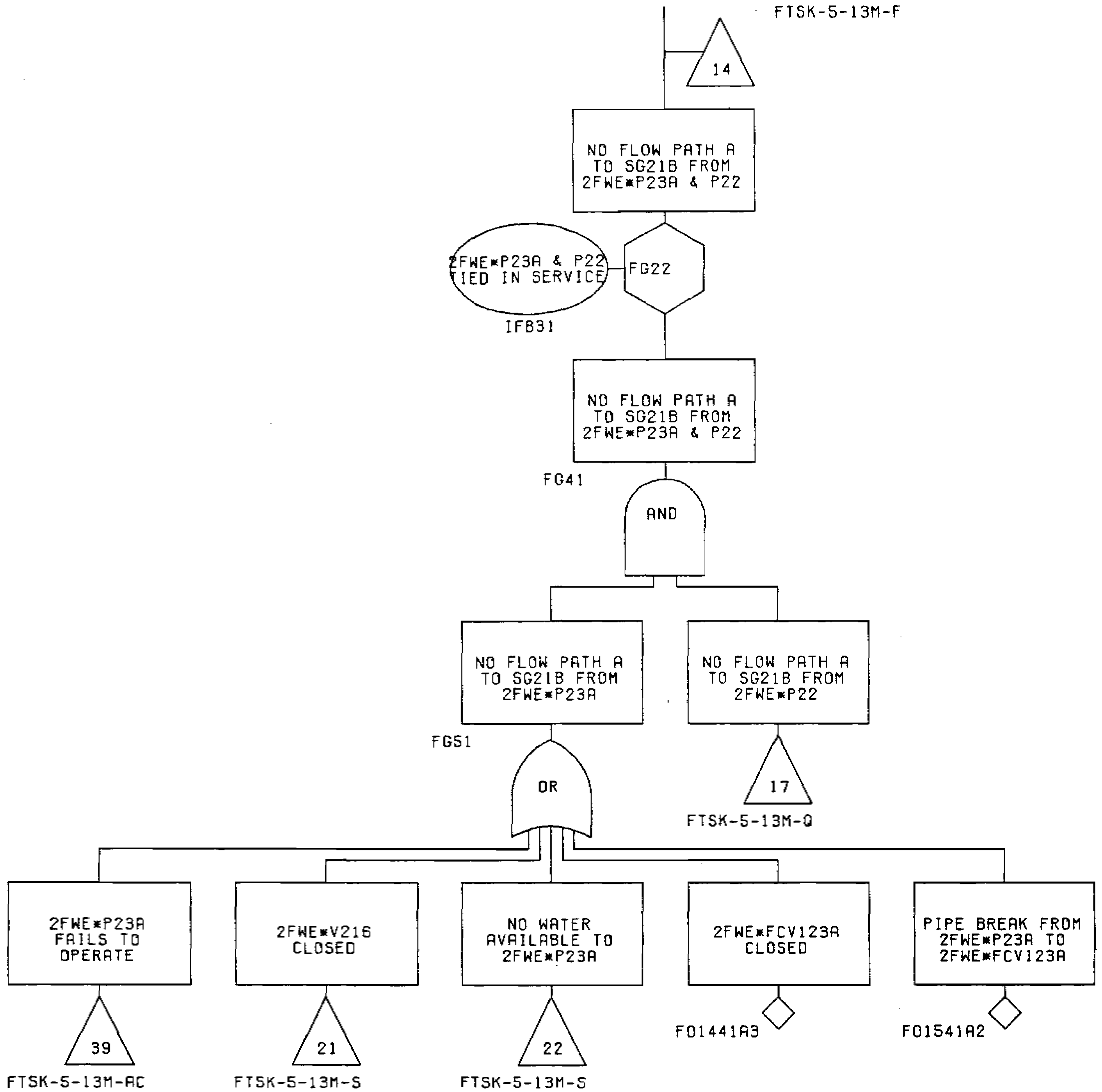
FAULT TREE DIAGRAM
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-L

C							
P	7	6	5	4	3	2	1
E							



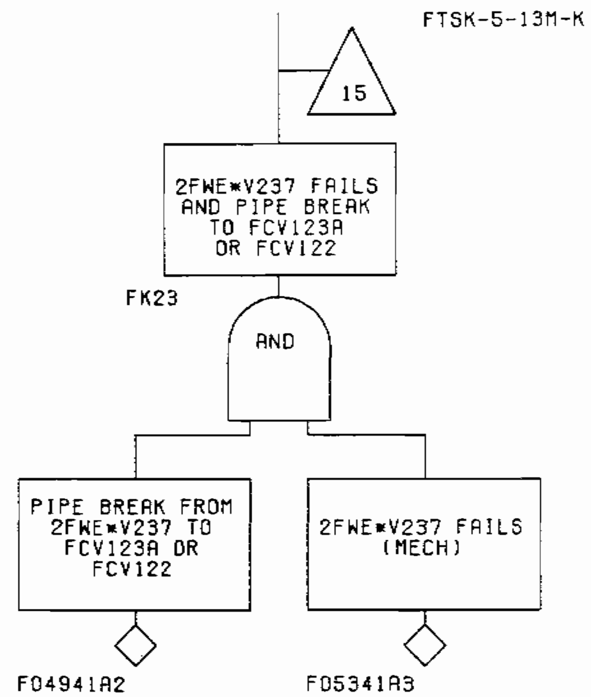
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-M



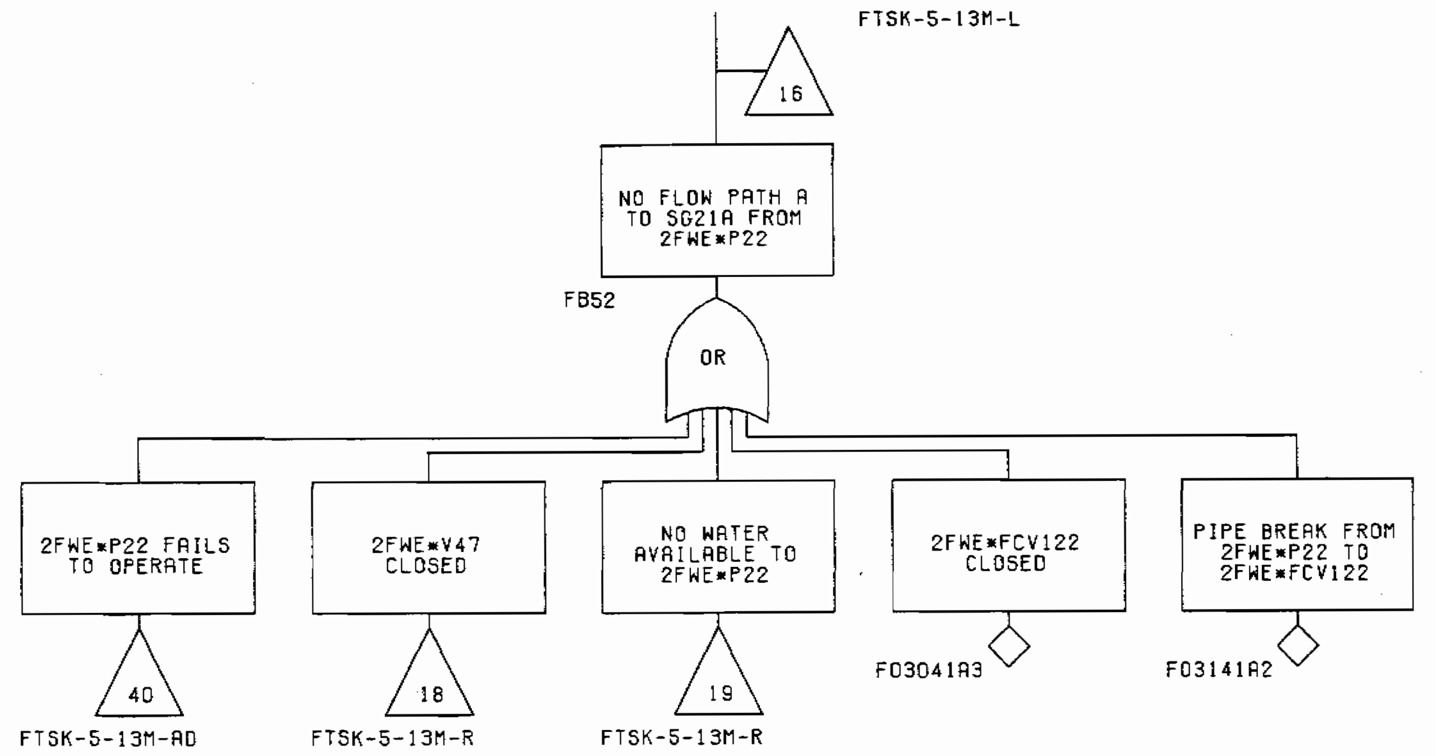
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-N

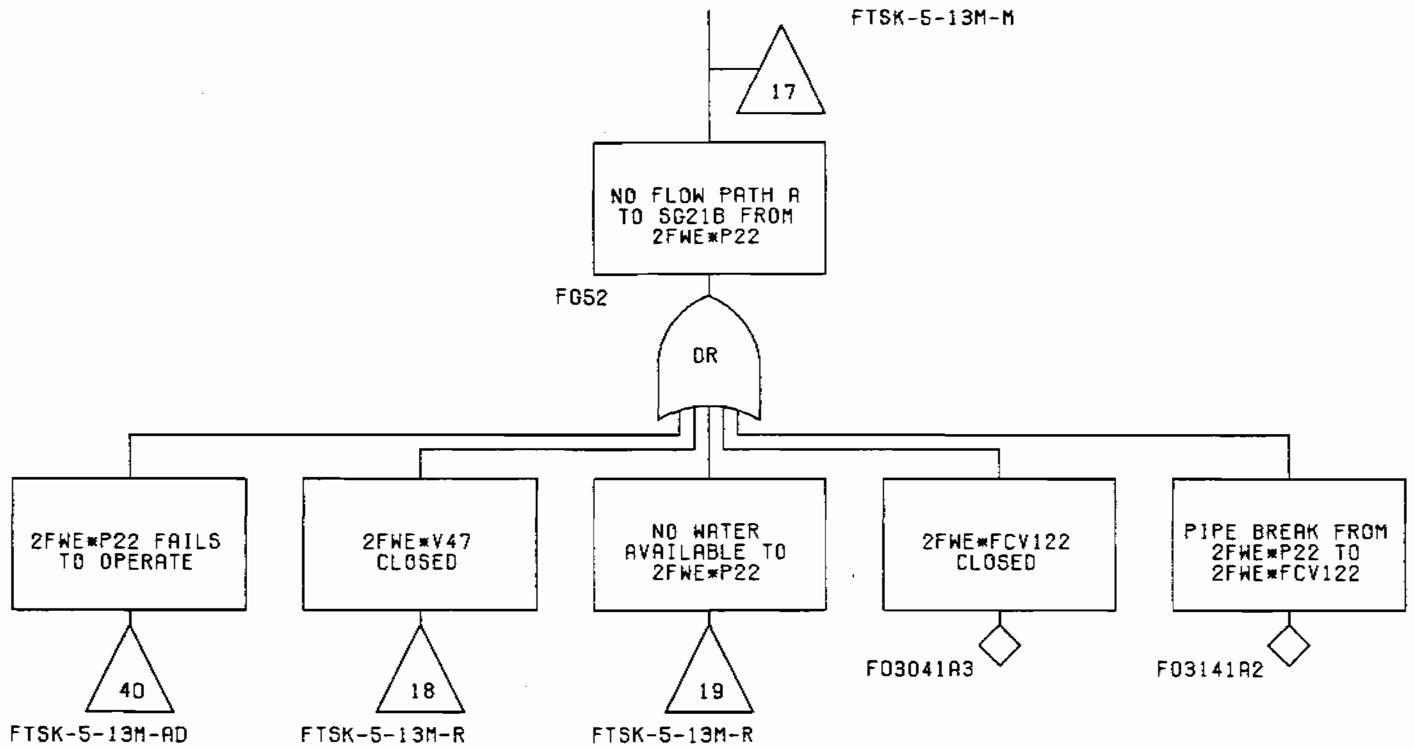


FAULT TREE DIAGRAM
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-P



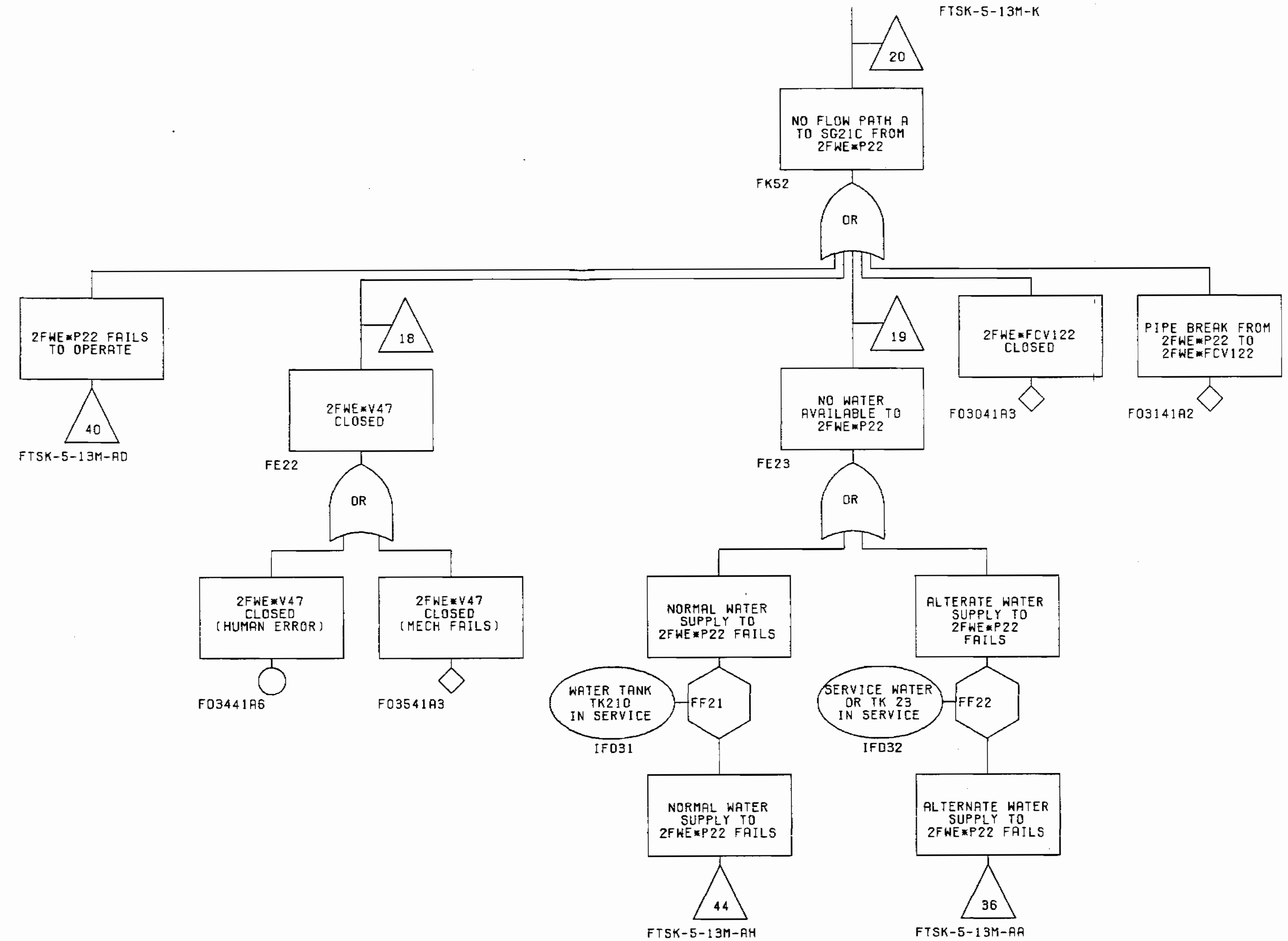
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-Q



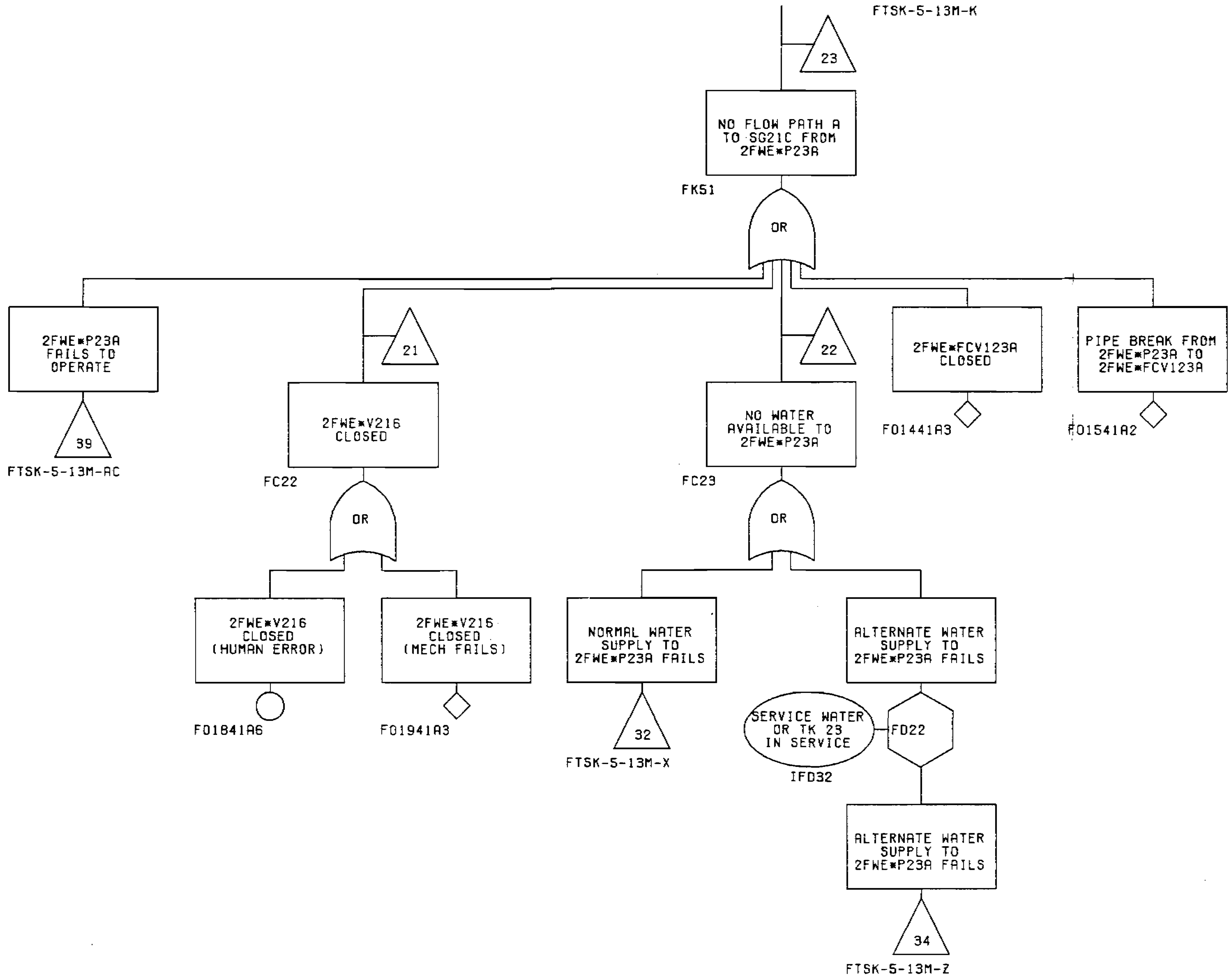
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-R

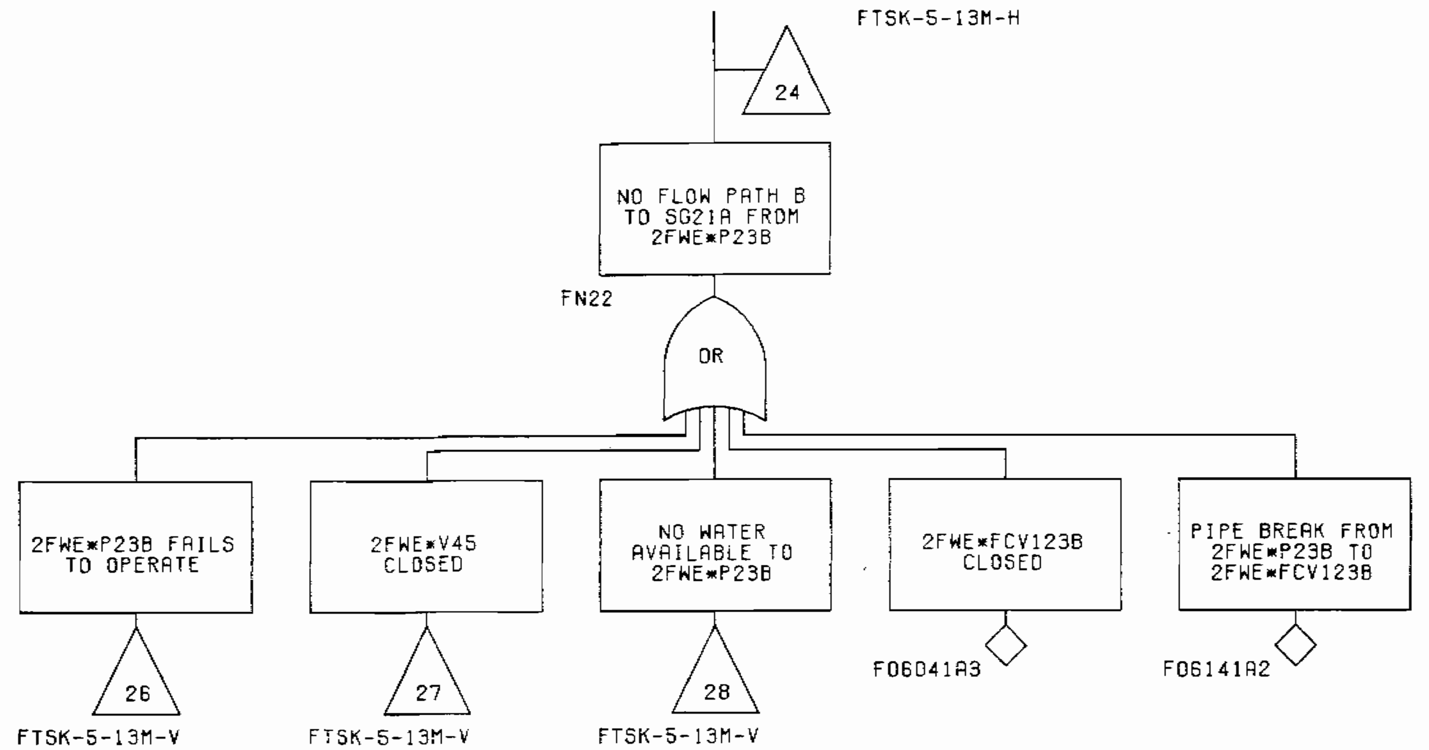


FAULT TREE DIAGRAM
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-S



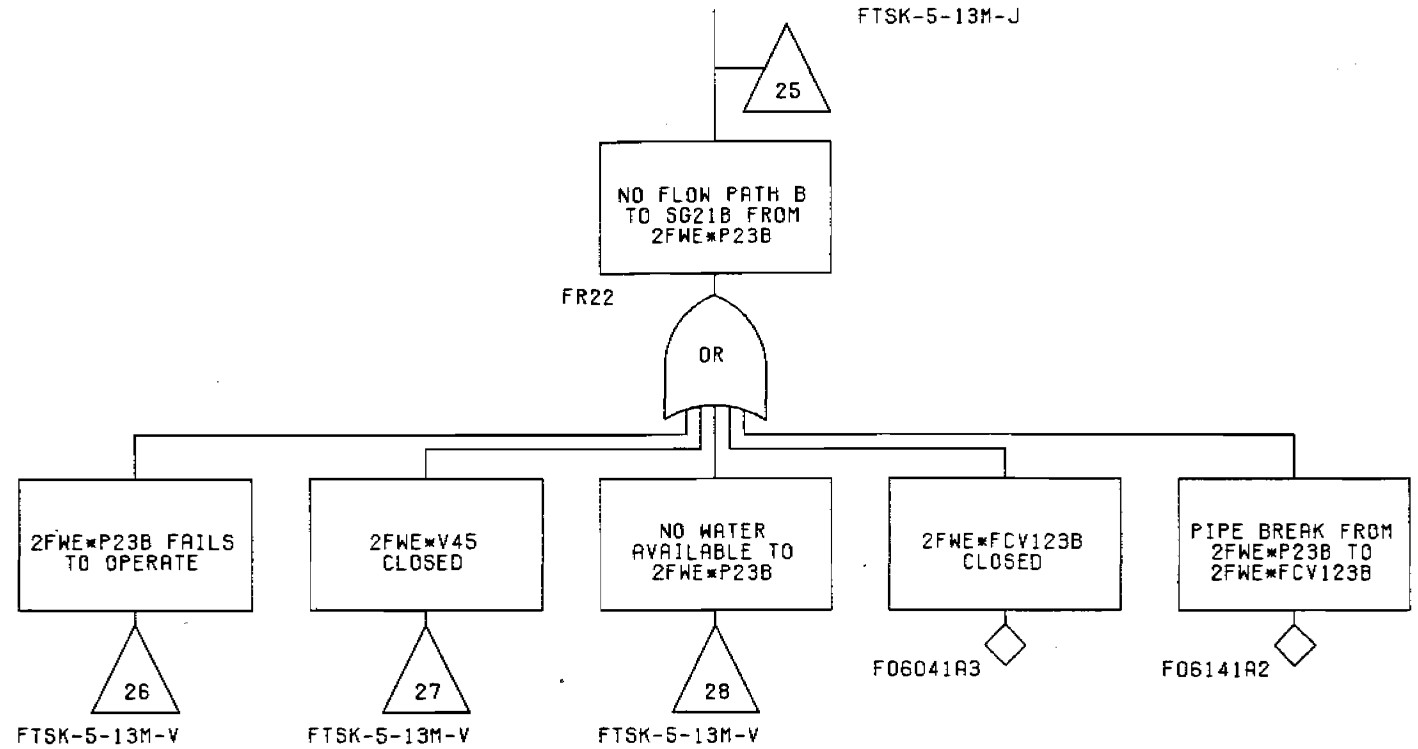
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-T



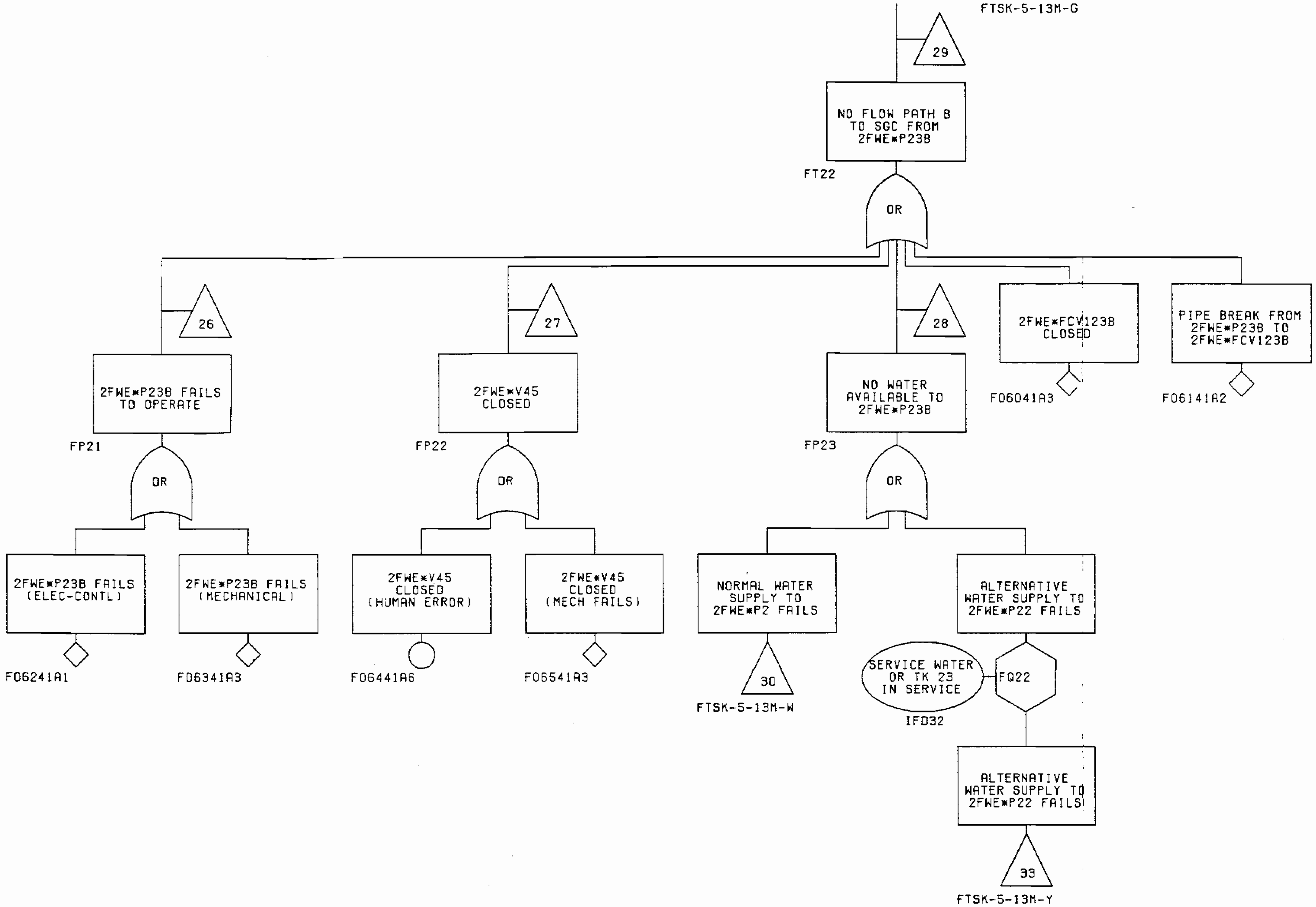
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-U

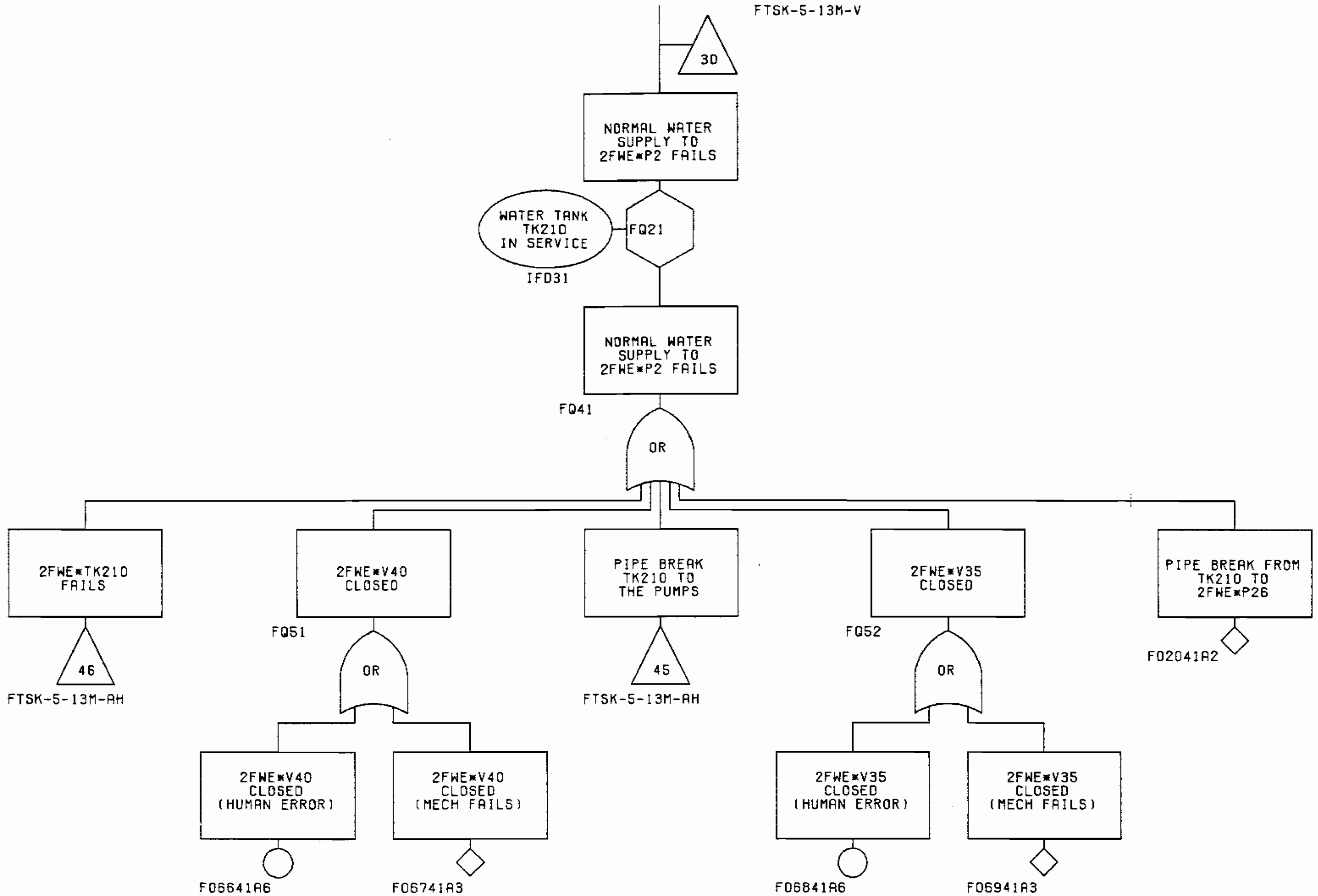


FAULT TREE DIAGRAM
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-V



FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-W

C								
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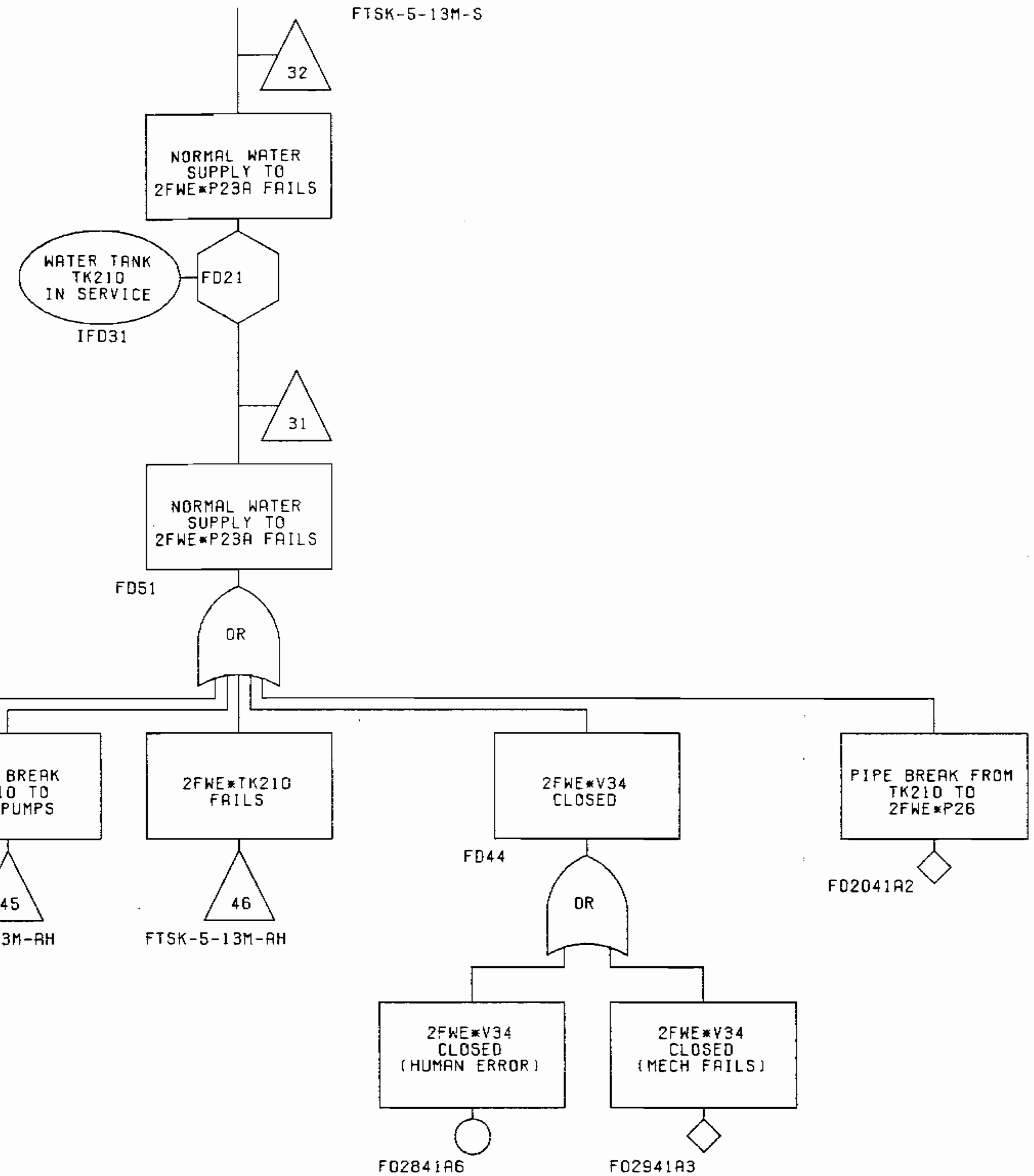
E								



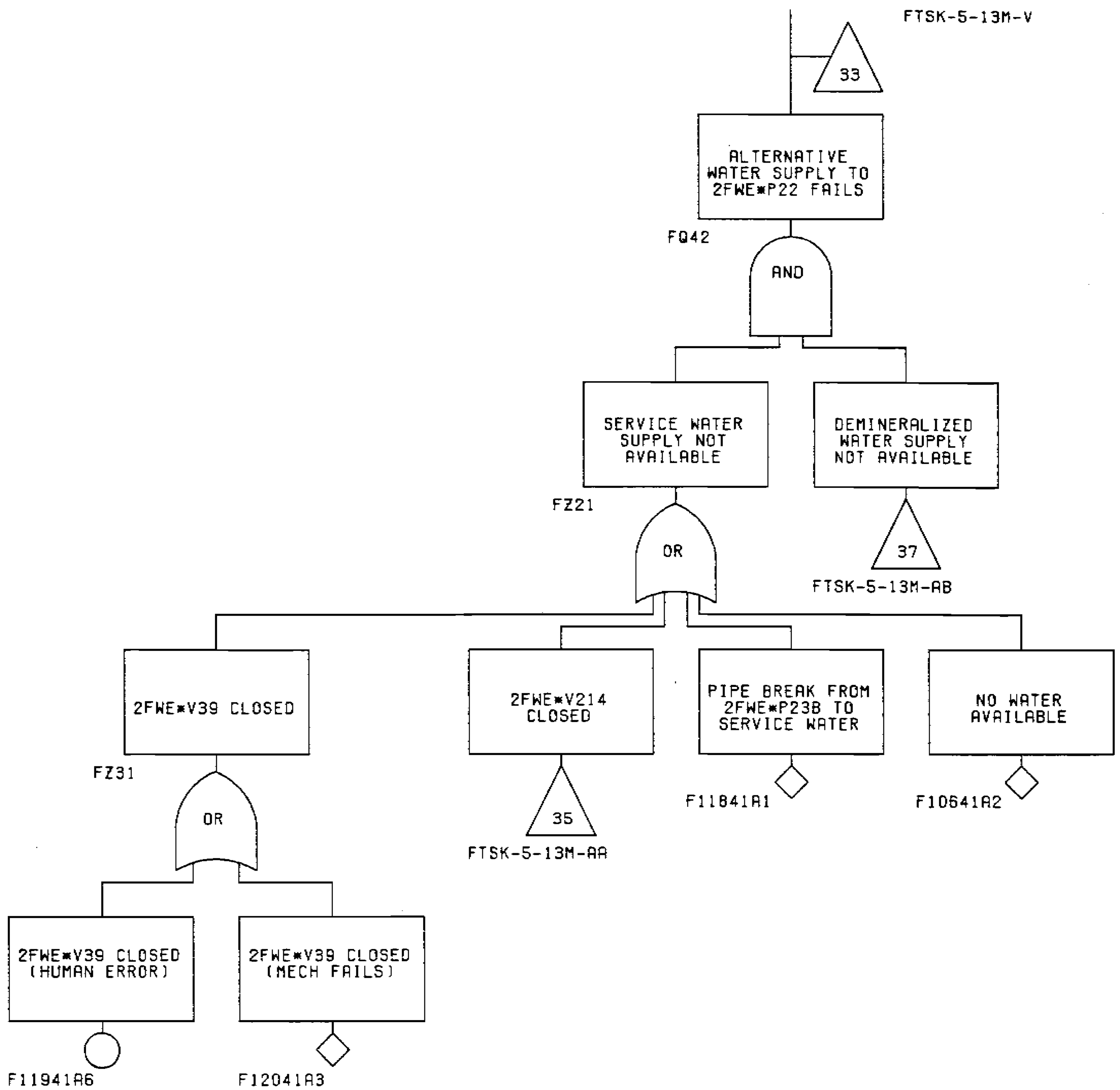
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

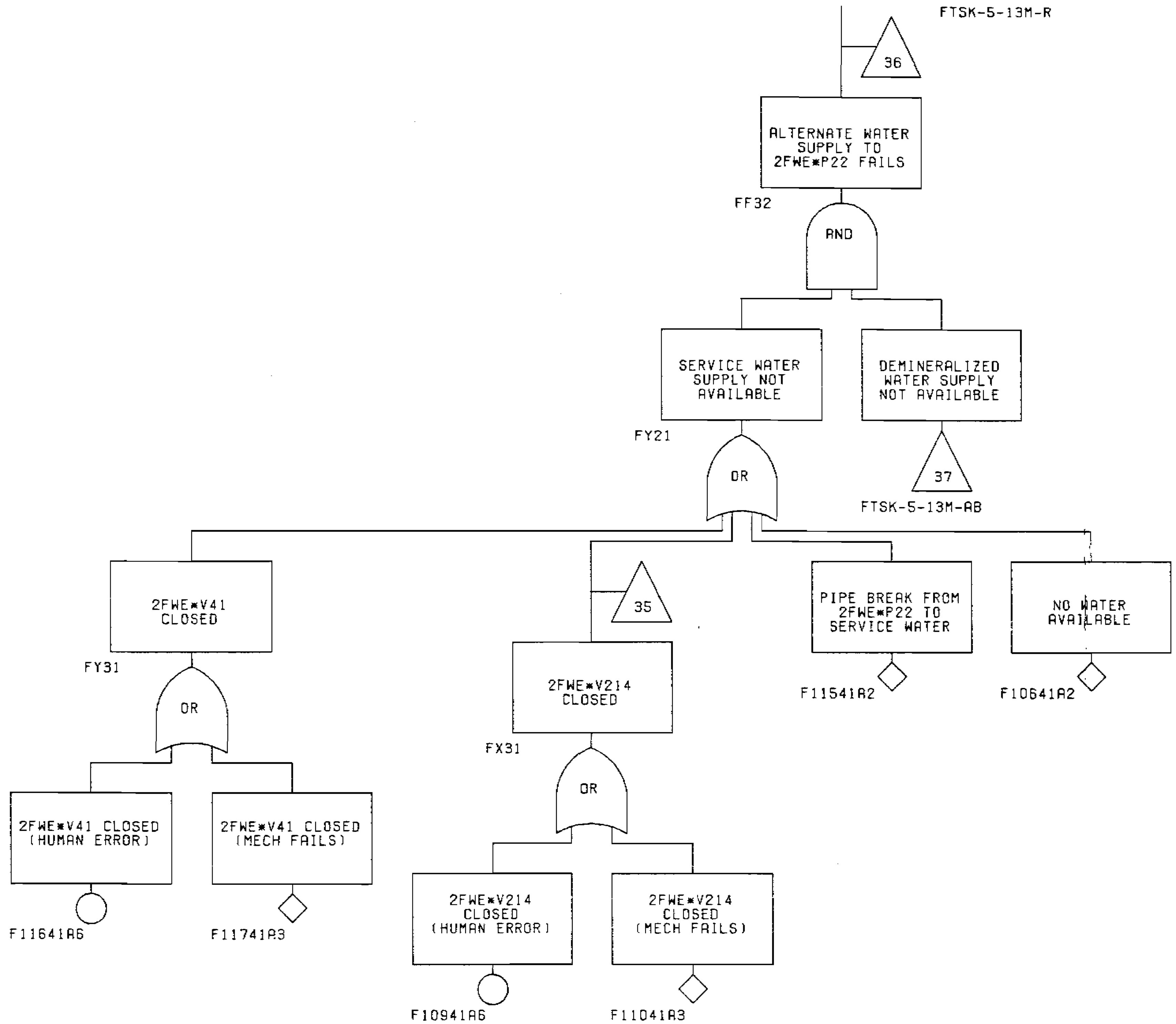
BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-X



FAULT TREE DIAGRAM
AUXILIARY FEEDWATER SYSTEM (MECH)
BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241
STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.
DRAWING NUMBER FTSK-5-13M-Y



FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AA

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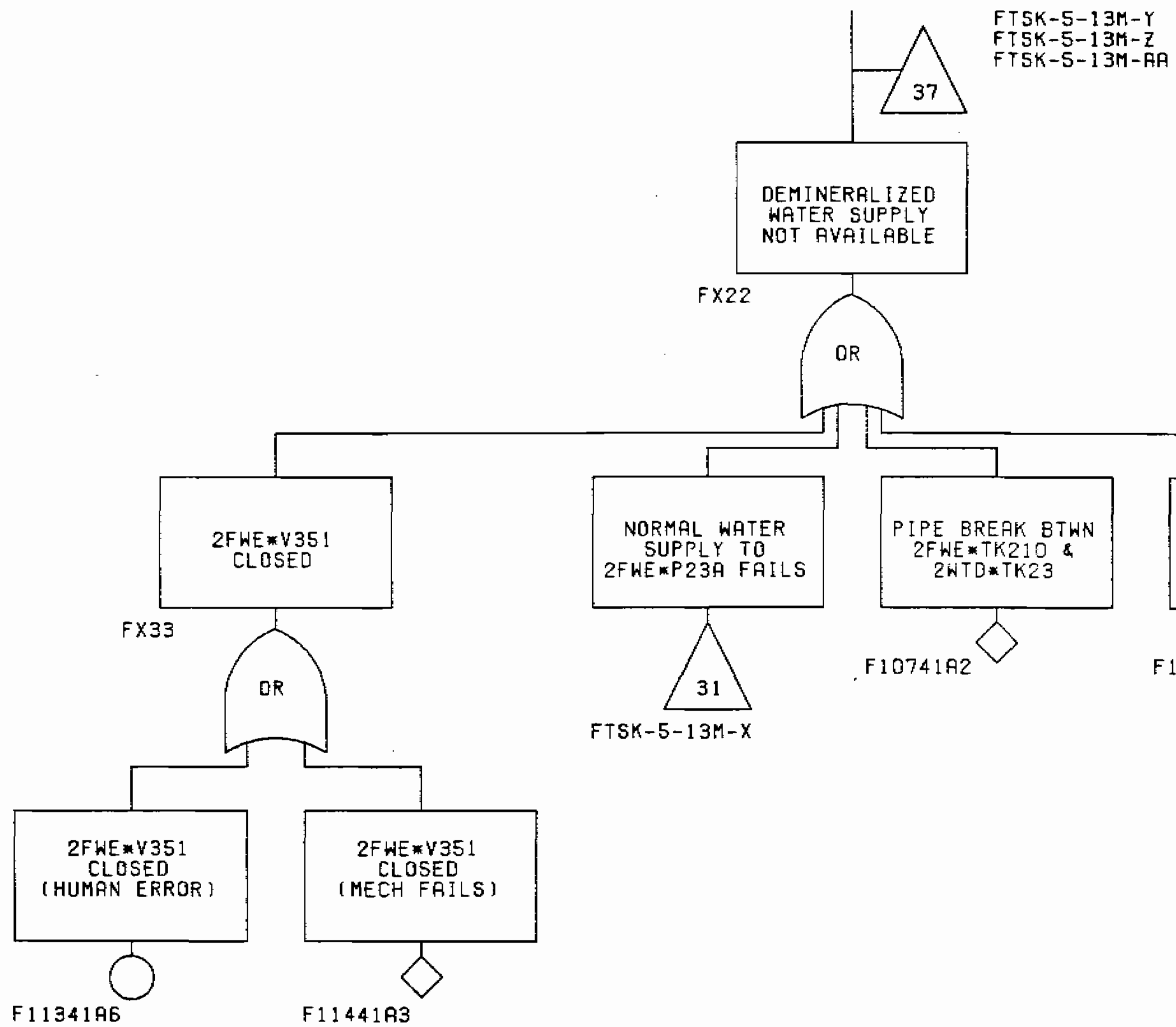
E							



FAULT TREE DIAGRAM

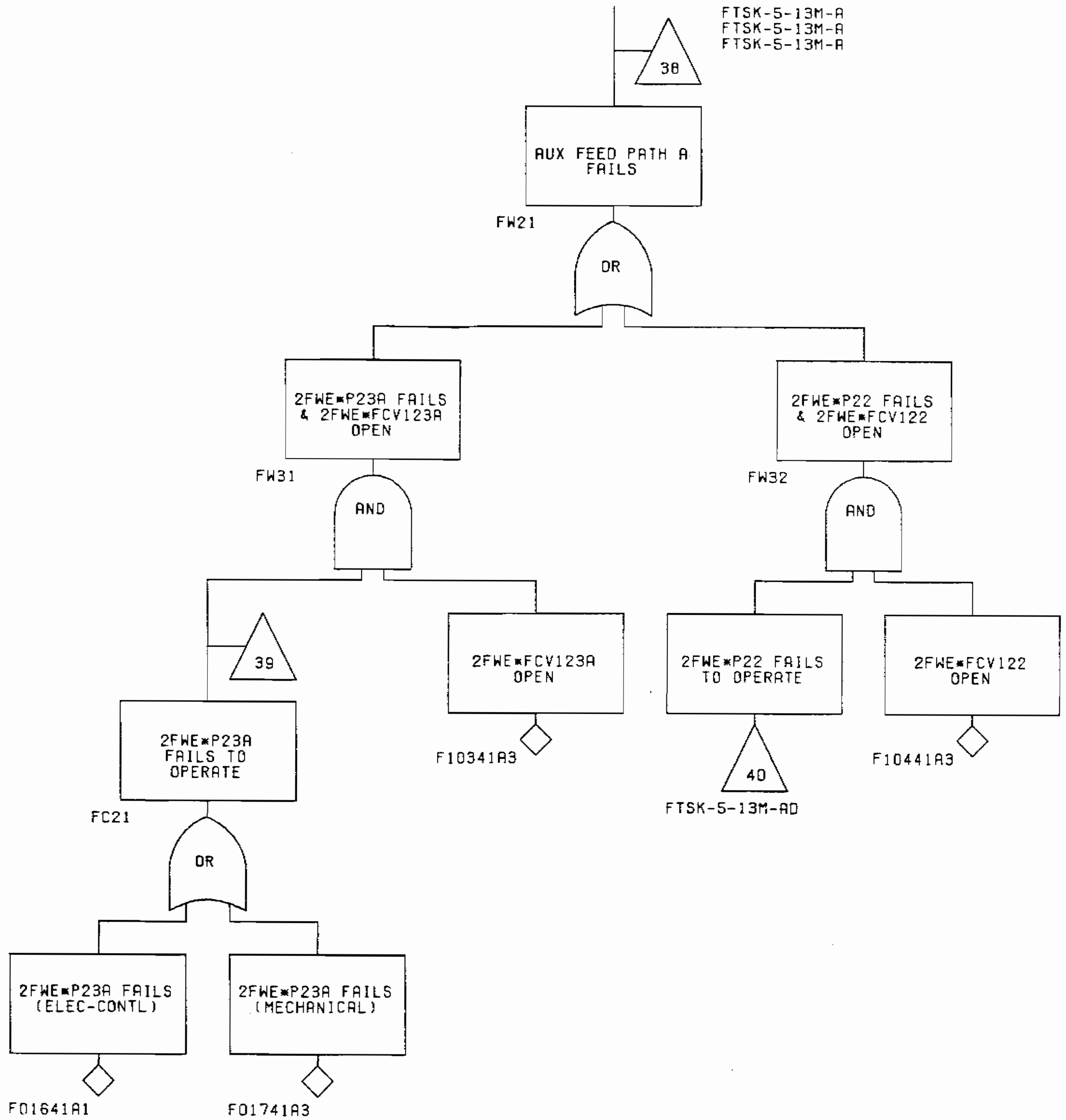
AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AB

C							
P	7	6	5	4	3	2	1
E							



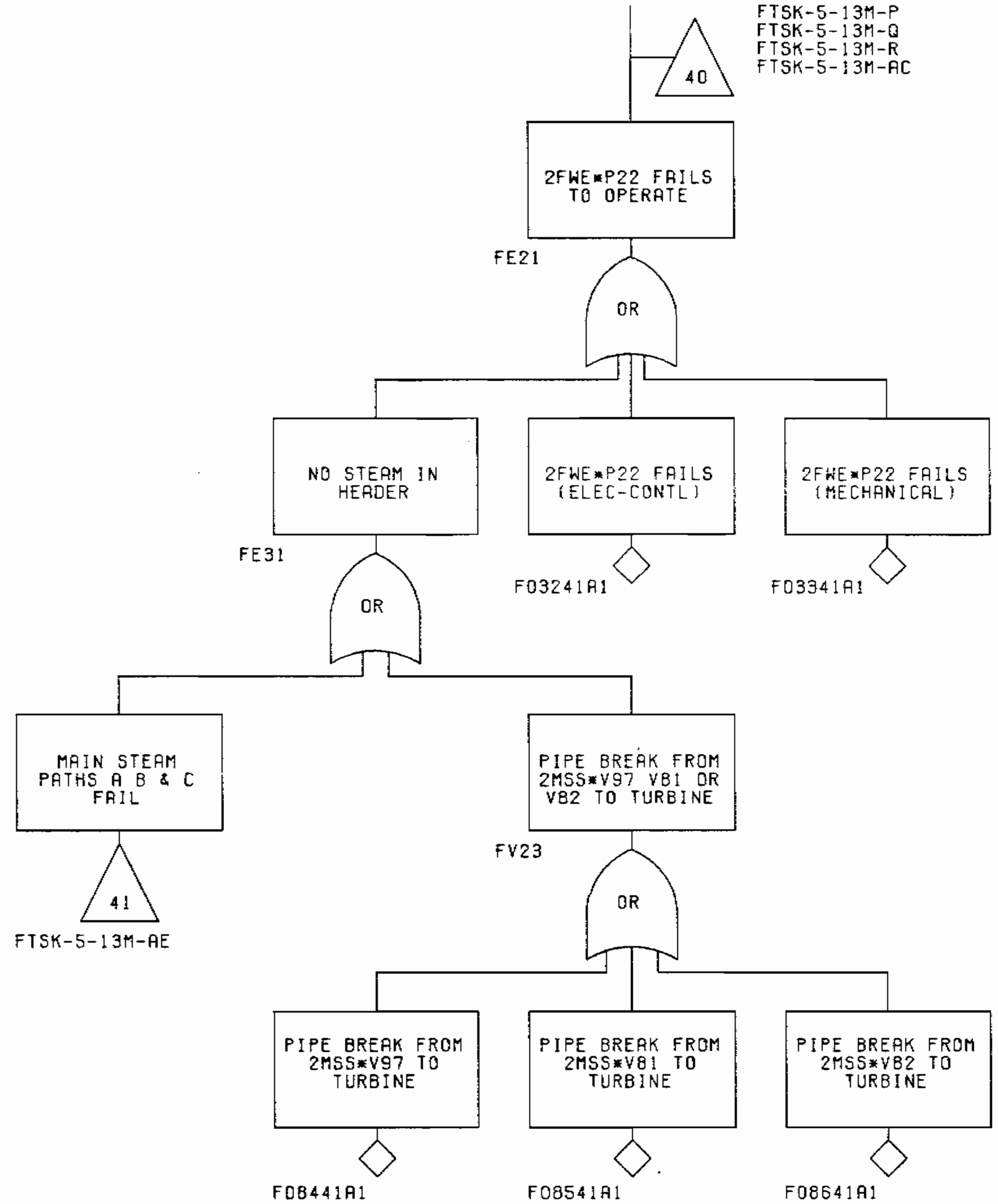
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AC



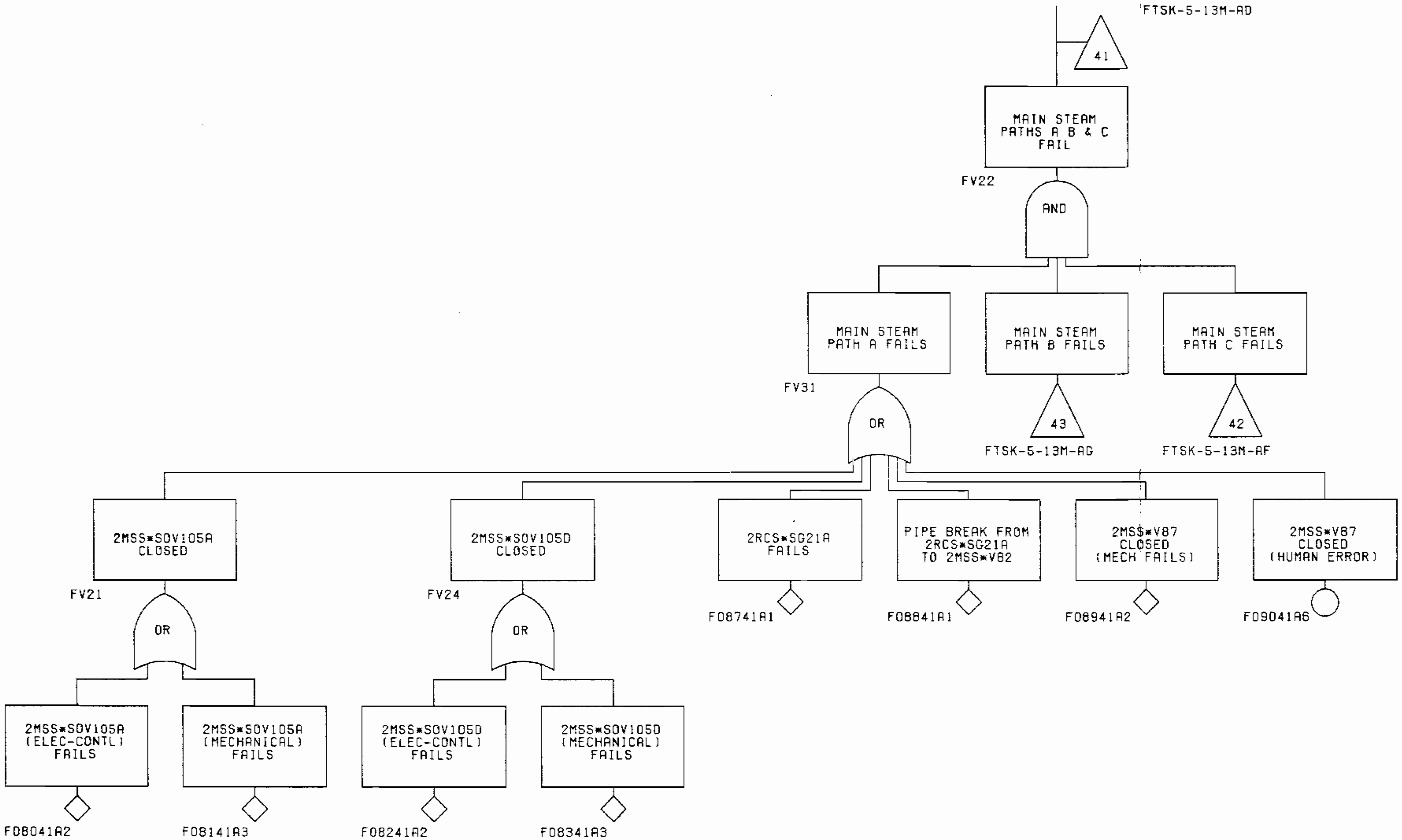
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AD



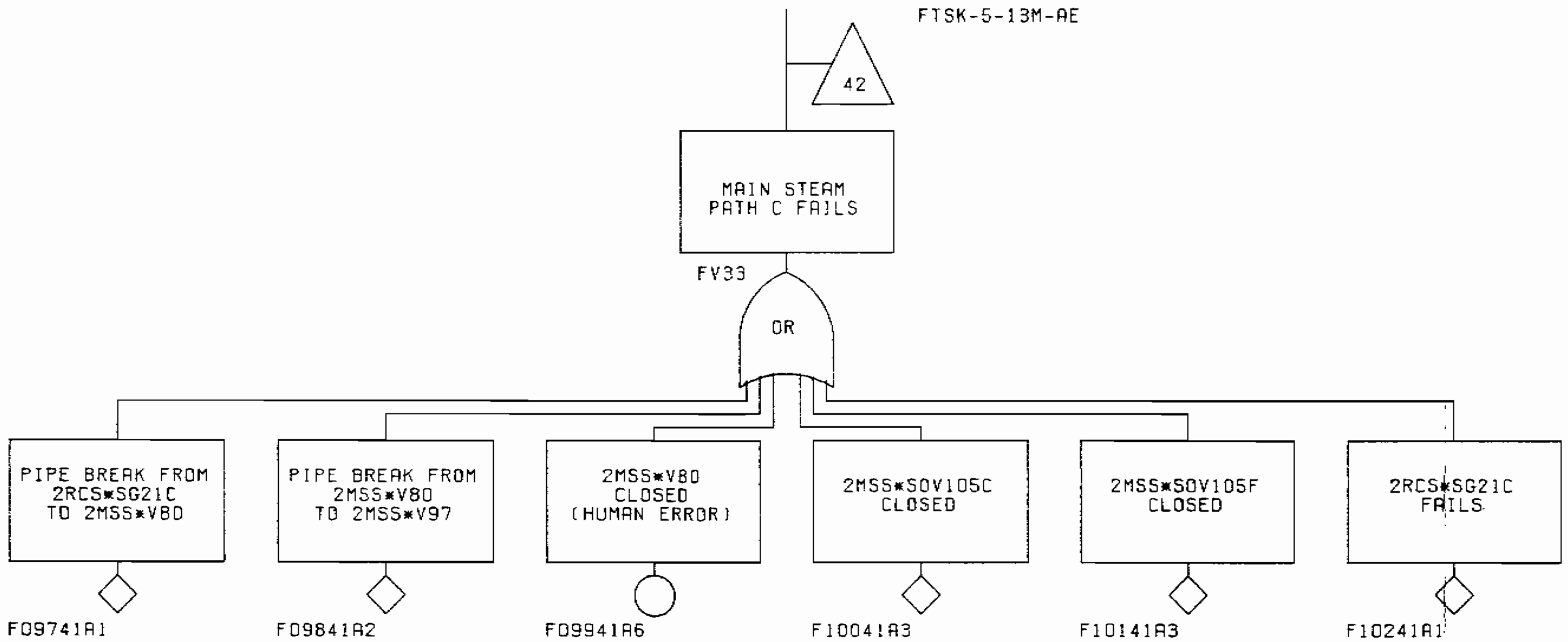
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AE



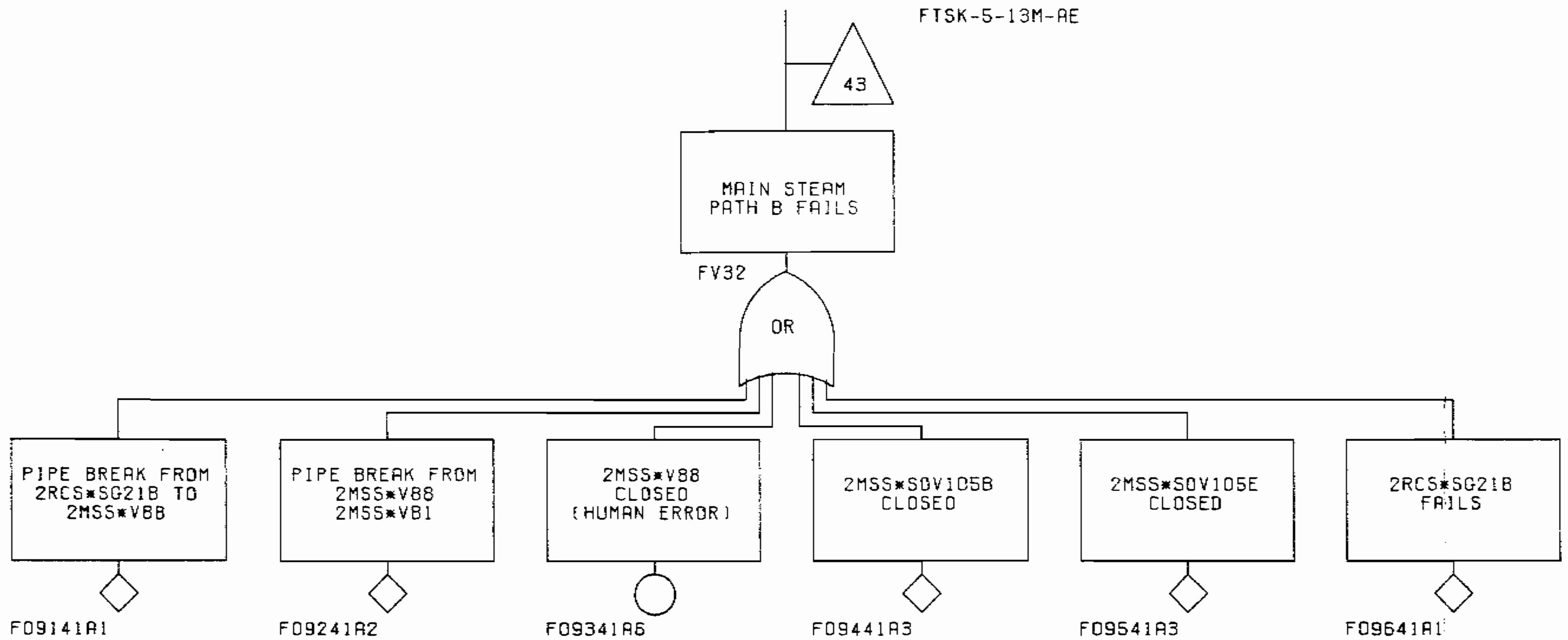
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AF



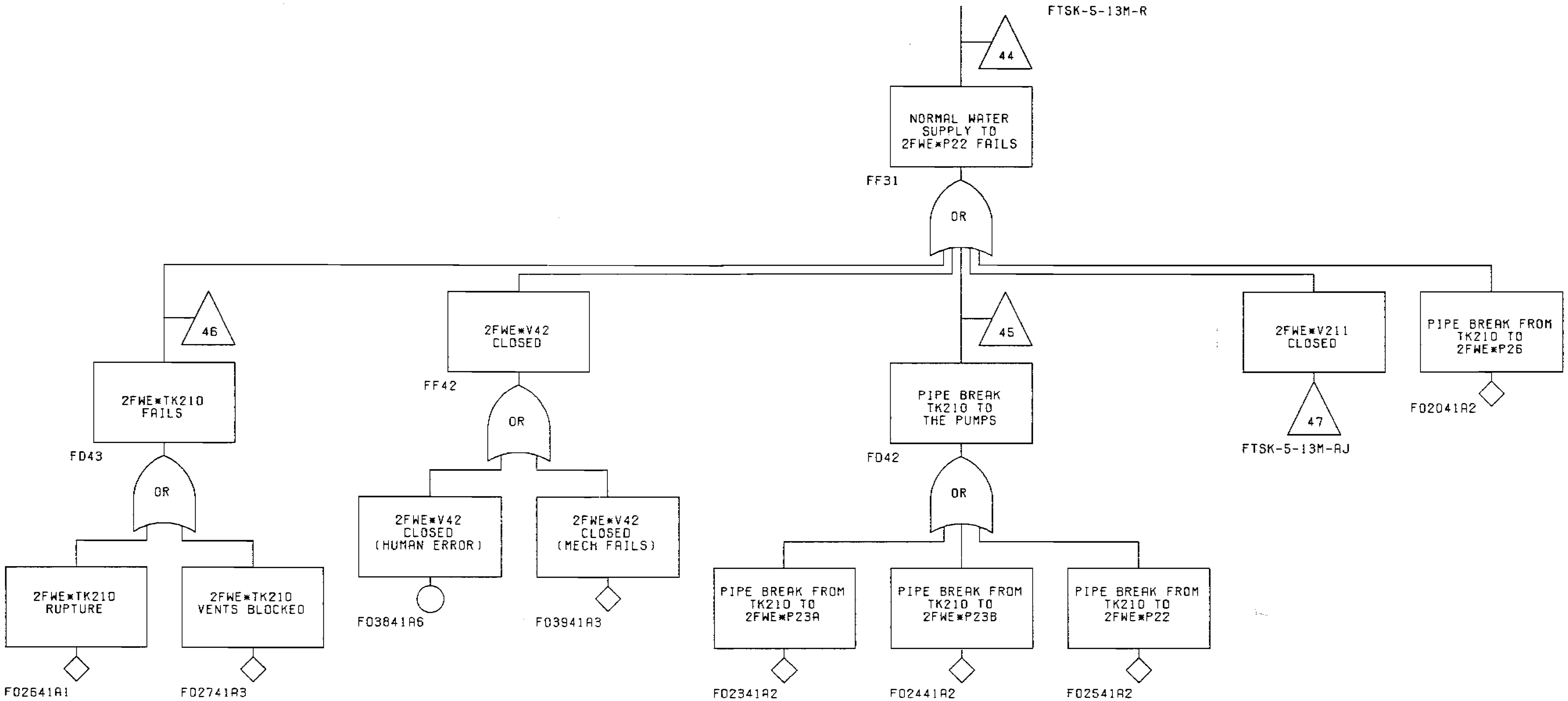
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AG



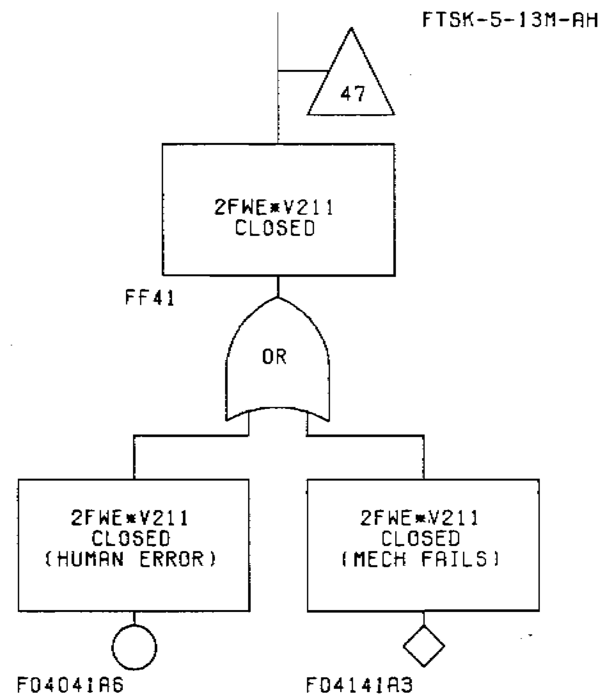
FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AH



FAULT TREE DIAGRAM

AUXILIARY FEEDWATER SYSTEM (MECH)

BEAVER VALLEY POWER STATION-UNIT2
DUQUESNE LIGHT COMPANY
J.O. 12241

STONE & WEBSTER ENGINEERING CORPORATION
BOSTON, MASS.

DRAWING NUMBER FTSK-5-13M-AJ