10.1 SUMMARY DESCRIPTION

The Steam and Power Conversion System converts thermal energy of the steam produced in the steam generators into electrical energy by means of the turbine generator unit. Exhaust steam from the low pressure turbines is condensed, reheated in the feedwater heaters and returned to the steam generators as feedwater. Refer to Table 10.1.0-1 for a summary of important design and performance characteristics of the Steam and Power Conversion System. The system with its major components can be divided into the following sections:

a) Main Steam Supply System from steam generator outlet to turbine throttle valves and including steam dump system to condenser and atmosphere.

b) Turbine generator including moisture separator/reheaters and auxiliary equipment.

c) Condensate System from turbine low pressure cylinder outlet connection to steam generator feed pumps. This system includes the condenser, condensate pumps, condensate booster pumps, condensate demineralizer and low pressure feedwater heaters.

d) Feedwater System from steam generator feedwater pumps to steam generator main feedwater connections. This system includes feedwater pumps, high pressure feedwater heaters, heater drain pumps, and feedwater flow control valves.

e) Steam Generator Blowdown System from steam generator blowdown connection to condenser including flash tank and filter system.

f) Auxiliary Feedwater System from and including auxiliary feedwater pumps to steam generator auxiliary feedwater connection.

Of the above systems only the Auxiliary Feedwater System is a safety related system; the Main Steam Supply System, Feedwater System and Steam Generator Blowdown System are safety related in part only, while the remainder are non-safety related.

Simplified flow diagrams showing the Steam and Power Conversion System and indicating those sections of the systems which are safety related are shown in Figures 10.1.0-1 through 10.1.0-6. The turbine generator is designed for performance at the maximum design load shown on Figure 10.1.0-7.

The steam generated in the three steam generators is supplied to the high pressure turbine. Steam leaving the high pressure turbine passes through the moisture separator-reheaters and then is admitted to the two low pressure turbines. A portion of the steam is extracted from the turbines for feedwater heating. Main steam from two out of three steam generators is available to supply the auxiliary feedwater pump turbine.

Exhaust steam from the two low pressure turbines is condensed and deaerated in the main condenser. The heat rejected to the main condenser is removed via the Circulating Water System and natural draft Cooling Tower.

The two condensate pumps take suction from the condenser hotwell and deliver the condensate through a full flow condensate polishing demineralizer system to the suction of two condensate booster pumps. The condensate polishing demineralizer system normally has full condensate flow flowing through it. Provisions exist however for the system to be partially or fully bypassed. The booster pumps deliver the condensate through two parallel trains of low pressure feedwater heaters of four stages each to the suction of two motor driven steam generator feed pumps.

The steam generator feed pumps discharge the feedwater through two parallel trains of high pressure feedwater heaters of one stage each and three feedwater flow control valves, one to each steam generator.

Drains from the high pressure heaters and from the moisture separators are collected in the fourth stage low pressure heaters and subsequently pumped into the steam generator feedwater pump suction by means of two heater drain pumps.

Shell drains from the remaining three low pressure feedwater heater stages are cascaded to the next lower pressure feedwater heaters and ultimately to the condenser. Alternate drains are also provided to automatically drain the high pressure, and low pressure feedwater heaters directly to the condenser.

In the event of reactor trip with loss of offsite power, the two motor driven auxiliary feed pumps or the turbine driven auxiliary feed pump will provide cooling water to the steam generators from the condensate storage tank and/or the ultimate heat sink via the Emergency Service Water System (Section 9.2.1). The motor driven pumps are powered by the plant diesel generators, and the turbine driven pump is powered by main steam extracted upstream of the main steam isolation valves of steam generators B and C.

The disposal of heat from the Reactor Coolant System following sudden load rejections or trip of the turbine generator unit is accomplished by bypassing steam produced in the steam generator to the condenser, rejecting it to the atmosphere, or both depending on conditions.

Control equipment is furnished which is capable of changing reactor output to follow system electric power demand.

In order to assist in maintaining steam generator secondary chemistry control, a blowdown system allows blowdown of a limited amount of water from the lower portion of each steam generator. Under normal conditions the flow, after passing through a flash tank and a heat-recovery and clean-up system, is returned to the cycle in the condenser.

The Steam and Power Conversion System is designed to the following principal codes and standards other than regulatory guides and design criteria.

1. ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components.

2. Power Piping Code ANSI B31.1

3. ASME Boiler and Pressure Vessel Code, Section XI, rules for in-service inspection of nuclear reactor coolant systems.

Protection of safety related systems, structures and components from the effects of natural and accidental phenomena are discussed in the following sections:

3.2 Classification of structures, components and systems

3.3 Wind and tornado loadings

3.4 Water level (flood) design

3.5 Missile protection

3.6 Protection against dynamic effects associated with the postulated rupture of piping

3.7 Seismic design

3.9 Mechanical systems and components

10.2 TURBINE-GENERATOR

10.2.1 DESIGN BASIS

The plant design integrates the turbine-generator and associated systems (TGS) with the reactor and its associated systems to obtain a safe, efficient power generating combination. The turbine-generator is designed for performance at the Maximum Design Load conditions given on Figures 10.1.0-7, and Table 10.2.1-1. The arrangement of the turbine and associated equipment with respect to safety structures and systems is shown on Figure 1.2.2-2.

Turbine-generator maximum design electrical load, corresponding to nominal full reactor power (2961.7 Mwt) is 1,034,600 kw when operating with rated steam conditions of 982 psia, 542 F at the turbine throttle valves and 2.99/4.13" Hg abs exhaust. The exhaust backpressure is a "reference" condition for the condenser and actual performance will vary depending on several factors, including the effect of circulating water inlet temperature on condenser backpressure.

The turbine-generator is not designed for operation under the stresses that could be imposed by the operating basis earthquake (OBE) or the safe shutdown earthquake (SSE).

The turbine-generator and accessories are classified as non-Seismic Category I and are designed in accordance with industry standards and, where applicable, in accordance with the requirements of ANSI Code for Power Piping, TEMA Standards for Heat Exchangers, NEMA Standards, IEEE Standards, Hydraulic Institute Standards, Regulations of NBFU, ASME Power Test Code for Steam Turbines, ASME Code Section VIII, AWS and ASTM.

The Nuclear Steam Supply System has the capability of following step load changes to a maximum of 10 percent of rated load, or ramped load change of 5 percent per minute of rated load over the range from 100 to 15 percent load without initiating operation of the Steam Dump System, reactor trip, or pressurizer pressure control system. See Section 10.4.4 for additional information on the Steam Dump System.

The Reactor Coolant System also maintains the reactor coolant average temperature (T_{avg}) within the prescribed limits by rod motion during load changes. See Section 7.7.1 for additional details.

The turbine-generator is tripped in the event of a reactor trip. The Reactor Protective System provides redundant signals of reactor trip to the Turbine Control System. See Section 7.2 for further information.

The Harris Plant is planned to be operated as base loaded generation.

10.2.2 DESCRIPTION

10.2.2.1 Introduction

The turbine-generator unit and accessories are supplied by Westinghouse Electric Corporation (now Siemens Energy, Inc.) and are suitable for outdoor installation. The turbine is a tandem compound, four flow exhaust, 1800 rpm unit with 45 in. last stage blades. The unit includes two moisture separators each with a single stage reheater. Turbine cycle performance conditions are given on Figure 10.1.0-7 and Table 10.2.1-1.

Figures 10.2.2-1 through 10.2.2-4 show, respectively, HP Turbine element, the turbine-generator outline, and details of the steam chest with control and throttle valves.

10.2.2.2 Generator Unit

The generator is a hydrogen inner-cooled unit. The generator with its brushless exciter is directly connected to the turbine shaft. The hydrogen for charging the generator and the carbon dioxide used for purging are supplied from a central gas storage area in the yard. Figures 10.2.2-5 and 10.2.2-6 show these systems. Figure 1.2.2-2 shows the location of the Gas Storage Area with respect to the Plot Plan. The Turbine Building is an open structure well ventilated by natural circulation which prevents the accumulation of hydrogen within the building. Fire protection is discussed in Section 9.5.1.

10.2.2.3 Turbine Unit

The steam produced in the steam generators is passed through the high pressure turbine. The high pressure turbine element, as shown on Figure 10.2.2-1 is of a double flow design, where steam from the four governor valves enters the turbine element through four inlet pipes. These pipes feed the double-flow inner casing and bladepath. Steam passes through the single diagonal stage and flows through nine stages of reaction blading where it is expanded and is then exhausted to the moisture separator/reheaters. Two horizontal, cylindrical-shell, combination moisture separators with single stage reheater assemblies are located alongside the turbine low pressure cylinders on the operating floor. The moisture separator/reheaters remove the moisture content and superheat the steam before entering the low pressure turbines, where the steam is further expanded through eight stages of reaction blading. Heating steam for the single stage reheaters is taken from the main steam header. From the low pressure turbines the steam is exhausted to the main condenser where it is condensed and deaerated.

The high pressure turbine has four throttle and four governor valves. One governor valve is located in each of the four steam inlet lines. The throttle valves are arranged in pairs and are located at the ends of two steam chest assemblies, where each communicates with either one of a pair of governor valves, also located in each steam chest assembly. The low pressure turbines have one reheat throttle and one reheat interceptor valve arranged in series in each of the four hot reheat lines. Therefore, each steam supply line to the high pressure and low pressure turbines is arranged such that a failure of one valve to close will not affect the shutdown of the turbine. All turbine throttle valves close in 0.25 seconds or less. This time includes 0.1 second signal delay time and 0.15 second valve closure time. This accident analysis for an ESF response time leading to a turbine trip is 2.5 seconds. This longer time is due to more components in the signal path.

The turbine throttle, governor, reheat, and intercept valves provided, protect the turbine from exceeding set speeds and protect the reactor system from abnormal surges. Valve arrangement as shown in Figures 10.1.0-1 and 10.1.0-2, along with the valve closure times of 0.25 seconds or less, prevent excessive turbine overspeed in the event of a TGS trip signal and a failure of any single valve to close.

A Turbine Lube Oil System supplies oil for lubricating the turbine-generator and exciter bearings. A bypass stream of turbine lubricating oil flows continuously through an oil conditioner to remove water and other impurities.

10.2.2.4 Extraction Steam System

The turbine supplies extraction steam to five stages of feedwater heating. The extraction steam system is shown on Figure 10.1.0-2. Extraction steam for high pressure feedwater heaters Nos. 5A and 5B is extracted from the sixth stage of the high pressure turbine and extraction steam for low pressure feedwater heaters Nos. 4A and 4B is extracted from the high pressure turbine exhaust upstream of the moisture separators. Extraction steam for low pressure feedwater heaters Nos. 3A, 3B, 2A, 2B, 1A and 1B is taken from the low pressure turbine stages Nos. 13, 15 and 16 respectively.

Shell side drains from high pressure heaters Nos. 5A and 5B are cascaded to low pressure heaters Nos. 4A and 4B from where the drains are pumped forward by two heater drain pumps into the feedwater pump suction header. Shell side drains from low pressure heaters Nos. 3A, 3B, 2A, and 2B are cascaded to the next lowest pressure feedwater heaters and ultimately through low pressure feedwater heaters Nos. 1A and 1B and discharged to the condenser.

Individual heaters are provided with alternate drains which will dump automatically directly to the condenser upon a high level in the respective heater. High pressure feedwater heaters Nos. 5A and 5B receive drains from the single stage reheaters in addition to the extraction steam. Low pressure feedwater heaters Nos. 4A and 4B receive the drains from the moisture separators in addition to extraction steam.

Extraction steam lines to all feedwater heaters, except to low pressure feedwater heaters No. 1 located in the condenser neck, are provided with motor operated isolation valves and reverse current valves. The reverse current valves are free swinging check valves provided with a positive closing mechanism consisting of a piston air cylinder, spring loaded to close the valve on loss of air in one second or less. The spring loaded air cylinder is to assist in closing the valve before extraction flow reversal has occurred. This cylinder cannot close the valve completely with both the associated heater and turbine in service. The motor operated valves are provided for manual isolation following a turbine trip and for maintenance purposes (closure time is approximately 1 minute).

In the event of a turbine trip or other actuation of the oil pilot valve, the reverse current valves will close and prevent turbine overspeed due to energy stored in the feedwater heaters which would tend to flow back toward the turbine. Similarly in case of sudden load reductions the reverse current valves although not energized to close will act to prevent stored energy from entering the turbine. Low pressure feedwater heaters No. 1 have been designed to assure that the stored energy is insufficient to result in turbine overspeed due to either a turbine trip or sudden load reduction.

10.2.2.5 Turbine Control and Overspeed Protection System

The Westinghouse (now Siemens Energy, Inc.) turbine generator unit utilizes a non-safety related, non-seismically designed Digital-Electric Hydraulic (DEH) control system which controls valve position, speed, and/or load depending on the reference parameter selected. The DEH control system consists of five major components:

a) A solid state electronic controller, which contains all logic and core memory for the system. The controller performs basic computations on reference and turbine feedback signals and generates an output signal to the steam valve actuators.

b) An operator's control panel in the Control Room contains various instrumentation and controls with regard to speed acceleration and various turbine variables such as speed and load references, valve position limits and loading rates.

c) Steam valve servo-actuators which position each steam valve based upon signals received from the electronic controllers.

d) A high pressure fluid control system which provides motive force to position the turbine steam valves in response to signals from the electronic controller.

e) A lube oil and mechanical/hydraulic trip system which is used as the control medium for the emergency trip valve.

During wide range speed control, the control reference is the desired value of the turbine generator speed. An operator can set or change the speed reference through various Control Panel actuators. Operator settings made at the panel are used by the electronic controller to position the steam valves by comparing the turbine speed to the reference settings selected by the operator. After synchronization, the load reference will be used to control the turbine.

During load control, the control reference is either the desired value of the governor valve position, and/or megawatts depending upon which feedback loop has been placed in service.

The DEH control system controls positioning of the throttle and governor valves and the intercept and reheat stop valves with actuators using hydraulic fluid pressure. The intercept and reheat stop valves are positioned in either the full open or full closed position while the throttle and governor valve actuators position those valves in any intermediate position to proportionally regulate the steam flow to the required amount. The throttle valve pilots control the steam flow during startup, and the governor valves control the steam flow for synchronizing and load control. The interceptor valves control the steam flow from the MSRs to the LP turbines. The reheat stop valves limit flow to the LP turbines in the event of a load rejection. Figures 10.2.2-7 through 10.2.2-9 are system schematics which include identifying numbers to valves and mechanisms.

Figure 10.2.2-10 shows the turbine emergency trip system and Figure 7.3.1-1, Sheet 7 of 7 indicates the turbine generator protection system input to the Solid State Protection System.

For speed control following load rejection, the OPC action of the electro-hydraulic control system interrupts steam flow at approximately 105 percent of the rated turbine speed by closing the control and intercept valves.

The turbine overspeed protection is provided by redundant mechanical and electrical trip mechanisms. The electrical trip mechanism includes the emergency trip valve which acts as a backup to the mechanical overspeed trip mechanism. This redundancy provides adequate protection against turbine overspeed in the event of high and moderate energy piping failures.

The DEH electrical overspeed device consists of magnetic pickups mounted at the turning gear spacer and shaft driven oil pump and speed cards mounted in the trip system cabinet, for a total of three speed inputs. The pickup output frequencies are converted into an analog signal and compared one to another to guard against erroneous signals, and then compared with a trip set point. The electrical overspeed trip logic incorporates an interlock with the generator output breakers such that both output breakers must be open to facilitate a turbine trip on electrical overspeed. When the turbine speed exceeds the setpoint of approximately 110 percent (1980 RPM) of the rated speed, with the generator output breakers open, all four auto stop emergency trip solenoid valves, 20/AST, are energized to drain EH fluid and thereby shut all turbine steam inlet valves.

All electrical trips including overspeed trip are effected through the 20/AST solenoid valves which are arranged in a series - parallel configuration into two channels. This arrangement requires at least one solenoid valve from each channel to be open to cause a trip.

The mechanical overspeed device includes a spring-loaded weight mounted in a transverse hole in the turbine shaft. The compression force of the spring is incrementally adjustable to achieve the desired overspeed trip setpoint. When the shaft speed exceeds this level, the weight will move outward, striking a pawl which will open a valve and provide a path (for the autostop control oil) to drain. The mechanical overspeed trip device is set to trip the turbine at 108 to 111 percent (1944 to 1998 RPM).

Both the electrical and mechanical overspeed devices can be tested during turbine operation without compromising the overspeed protection during the test. The electrical overspeed trip logic incorporates a keylock switch to bypass the generator output breaker interlock for testing.

The emergency trip system, in addition to protection against turbine overspeed, provides protection against critical situations which might cause damage to the unit if not immediately taken out of service. Electro-hydraulic in design, the system provides:

a) Redundant overspeed trip signals

b) On line testability

c) Provision for detection and diagnosis of failed devices

d) Provision for in-service maintenance

The turbine protection system continually monitors turbine parameters. If a parameter is exceeded the protection system will trip the turbine by closing all steam admission valves. The closure time for these steam admission valves is less than one second.

The turbine protective trips that will trip the turbine due to mechanical failures are listed below:

a) Deleted

b) Turbine Thrust Bearing Wear

c) Turbine Overspeed (DEH and mechanical)

d) Turbine Bearing Oil Pressure Low

e) Condenser Vacuum Low

The turbine protective trips that will trip the turbine due to generator and associated equipment electric faults are listed below:

a) Control Rod Drive Mechanism (CRDM) Power Bus Breaker-Reactor Trip Breaker Open

b) Control Rod Drive Mechanism (CRDM) Power Bus Breaker-Reactor Trip By Pass Breaker Open

c) Safety Injection System (SIS) Operated

d) Generator Lock-out Relay Trip

e) Steam Generator HI-HI level

f) Loss of Power to Emergency Trip Cabinet

g) Loss of Power to DEH Controller

h) ATWS Mitigating System Actuation Circuitry (AMSAC) actuated

The initiating Electric fault signals for actuation of (d), the Generator Lock-out Relay, are listed below:

a) Main Generator Multi-Function Relay MFRA/1571

b) Main Generator Multi-Function Relay MFRB/1574

c) Main Transformer Tie Directional Ground Relay

d) Main Transformer Multi-Function Relay MFRMT/1572B Operated

e) Auxiliary Transformer Multi-Function Relays MFRUTA/1572C and MFRUTB/1572C

f) Main Transformer No. 1 Bus Breaker Fail Relay

g) Main Transformer No. 1 Tie Breaker Fail Relay

h) Generator High Voltage Breaker Closed and Exciter Field Breaker Open

i) Auxiliary Transformer Fault Pressure Relay

j) Auxiliary Transformer Overcurrent Relays 50/51/UTA/1575C and 50/51/UTB/1575C

k) Main Transformer Fault Pressure Relay

l) Generator & Main Transformer Differential Relay

10.2.3 TURBINE DISK INTEGRITY

As described in Section 3.5, the plant is designed to protect safety related systems and components against the effects of a postulated turbine missile. Turbine generator design features such as the speed control system discussed in Section 10.2.2 and the turbine disk integrity program discussed below make the possibility of generating a turbine missile remote.

10.2.3.1 Materials Section

10.2.3.1.1 High pressure turbine

The high pressure turbine element, as shown on Figure 10.2.2-1 is of a double flow design, which tends to be thrust-balanced. Steam from the four governor valves enters the turbine element through four inlet pipes. These pipes feed the double-flow inner casing and bladepath. Steam passes through the diagonal stage and flows through the reaction blading.

The high pressure rotor is made of NiCrMoV alloy steel. The minimum mechanical properties are as follows:

Tensile strength; 118 ksi (820 MPa), minimum

Yield strength; 84 ksi (580 MPa), minimum (0.2 percent offset)

Elongation in 2 in.: 16 percent, minimum

Reduction of Area: 50 percent, minimum

Impact Strength, Charpy V-Notch: 74 ft. lbm. (100 Joule) minimum at room temperature

50 percent fracture appearance transition temperature: -22 deg F (-30 deg C), maximum

10.2.3.1.2 Low pressure turbines

The double flow low pressure turbines incorporate high efficiency blading and diffuser type exhaust design. The low pressure turbine cylinder is fabricated from carbon steel plate to provide uniform wall thickness, thus minimizing thermal distortion. The entire outer casing is subjected to low temperature exhaust steam.

The disks are made of NiCrMoV alloy steel. There are two identical sets of five disks, one set for each of the two flows. Each disk in a set is numbered; the disk closest to the transverse centerline is designated number 1*. When the turbine is in operation each disk experiences a different stress and is, consequently, machined from a suitable grade of alloy steel. Current data and calculations indicate that disk number 2 experiences the highest stress, while disk number 5 experiences the lowest. The mechanical properties of each of the disk materials at room temperature are as follows:

	Discs 1,3,4&5	Disc 2
Elongation in 2 in., percent minimum:	17	16
Reduction of Area, percent minimum:	43	40
Impact strength Charpy V-Notch:	50 ft. lbm, minimum at room temperature	
50 percent fracture appearance transition temp:	OF. maximum	

Disk	Yield Strength (psi) Min.	Ultimate Strength (psi) Min.
1	110	120
2	120	130
3	110	120
4	110	120
5	110	120

The rotors are made of NiCrMoV alloy steel. The minimum mechanical properties are as follows:

Tensile Strength: 115 ksi, minimum

Yield Strength: 100 ksi, minimum (0.2 percent offset)

Elongation in 2 in.: 17 percent, minimum

Reduction of Area: 50 percent, minimum

Impact Strength, Charpy V-Notch: 40 ft. lbm, minimum at room temperature

50 percent Fracture Appearance Transition Temperature: 50 F, maximum

The above listed mechanical properties were all obtained from test results at the Westinghouse shop.

* Only disks numbered 4 and 5 are shrunk on. Disks numbered 1, 2, and 3 are integrally machined from the rotor stock.

10.2.3.2 Fracture Toughness

The fracture toughness for turbine disk is specified by the turbine manufacturer in his material specification. The ratio of the fracture toughness (K_{IC}) of the disk and rotor materials to the maximum tangential stress at speeds from normal to design overspeed should be at least 2 in. at minimum operating temperature (540 F). Suitable material toughness is obtained through the use of materials described under Section 10.2.3.1 above and by the use of improved mill techniques during the manufacturing process. Sufficient warm up time is specified in the turbine operating and maintenance instructions to prevent a brittle fracture during startup.

10.2.3.3 High Temperature Properties

The operating temperature of the high pressure rotor is considerably below the creep temperature of the material, therefore stress rupture properties are not applicable.

10.2.3.4 Turbine Disk Design

A design overspeed of 120 percent of rated speed is the highest anticipated speed resulting from a loss of load. This is based on the precept that, should the turbine speed governing systems overspeed protection controller be incapacitated, on loss of full load the turbine is tripped with 111 percent of rated speed by either the mechanical overspeed trip mechanism or the electrical emergency trip device. If the command of the overspeed protection controller is carried out properly, all the governor and intercept valves will be closed and the turbine speed will be kept below 120 percent.

Present manufacturing and inspection techniques for turbine rotor and disk forgings make the possibility of undetected flaws extremely remote. Forgings are subject to inspection and testing both at forging suppliers and at Westinghouse (now Siemens Energy, Inc.). Current design procedures are well established and conservative, and analytical tools such as finite element and fracture mechanics techniques allow in depth analysis of any potential trouble spots such as areas of stress concentration or inclusions, which could give rise to crack propagation.

Turbine assembly is designed to withstand normal and anticipated transients and accident conditions resulting in a turbine trip without loss of structural integrity.

10.2.3.5 Preservice Inspection

The low pressure turbine rotor shaft and disks are heat treated NiCrMoV alloy steel procured to specifications that define the manufacturing method, heat treating process and the test and inspection methods. Specific tests and test documentation, in addition to dimensional requirements, are specified for the forging manufacturer.

Inspections and tests are conducted on the low pressure turbine rotor shaft at the forging manufacturer's plant as follows:

a) The ladle analysis of each heat of steel or the weighted average analysis on multi-heat ingots is to be within the chemical composition limits defined by the specification.

b) Following heat treatment for mechanical properties but prior to stress relief, all shaft diameters and faces are subjected to ultrasonic tests defined in detail by a

Westinghouse (now Siemens Energy, Inc.) specification which is similar to the requirements of ASTM A-418.

c) After all heat treatment has been completed, the shaft forging is subjected to a thermal stability test as defined by a Westinghouse (now Siemens Energy, Inc.) specification which is more restrictive than the requirements of ASTM A-472.

d) After the bore of the shaft is finished machined, the bore surface is visually inspected and wet magnetic particle inspected as is defined in detail by a Westinghouse (now Siemens Energy, Inc.) specification which exceeds the requirements of ASTM A-275.

e) Utilizing specimens removed from the shaft forging at specified locations, tensile, Charpy V-Notch impact and FATT properties are determined following the test methods defined by ASTM A-370.

After the shaft is finished machined at Westinghouse (now Siemens Energy, Inc.), the outside shaft surfaces are fluorescent magnetic particle examined as defined by a Westinghouse (now Siemens Energy, Inc.) specification which is similar to ASTM E-138.

Inspections and tests are conducted on the low pressure turbine rotor disks at the forging manufacturer's plant, as follows:

a) The ladle analysis of each heat of steel or the weighted average analysis on multi-heat ingots is to be within the chemical composition limits defined by the applicable specification.

b) After heat treatment for mechanical properties but prior to stress relief, the complete disk forging is subjected to ultrasonic examination. This ultrasonic test is defined by a Westinghouse (now Siemens Energy, Inc.) specification which is similar to the requirements of ASTM A-418.

c) The tensile, Charpy V-Notch impact and FATT properties are determined from specimens removed from the disks at specific locations. Test methods used for determining these mechanical properties are defined by ASTM A-370.

After the disks are finished machined at Westinghouse (now Siemens Energy, Inc.), all surfaces except blade grooves are fluorescent magnetic particle examined as is defined by a Westinghouse (now Siemens Energy, Inc.) specification which is similar to ASTM E-138.

After the preheated disks are assembled to the low pressure rotor shaft to obtain the specified interference fit, holes are drilled and reamed for axial locking pins at the rotor and disk interface. These holes are fluorescent penetrant inspected as is defined by a Westinghouse (now Siemens Energy, Inc.) specification which is similar to ASTM E-165.

Prior to shipping, each fully bladed rotor is balanced and tested to 120 percent of rated speed in a shop heater box.

The high pressure turbine rotor for low temperature light water reactor applications has essentially the same basic material composition as the low pressure rotor shafts. This NiCrMoV alloy steel forging is subjected to test and inspection requirements that are similar to the low pressure rotor shafts, and included dimensional and visual inspection (radial and axial runout checks), chemical composition analysis, heat treatment check of data, mechanical properties verification (tensile and impact tests), ultrasonic tests, magnetic particle (MT) examination of surface and borehole and overspeed test.

10.2.3.6 In-Service Inspection

The in-service inspection program is designed to assure disk flaws that might lead to brittle fracture of the disk at speeds up to design speed will be detected. All major components of the system are accessible for inspection.

There are three types of turbine valves. These valves are grouped by design. The three types are throttle valves, governor valves, and low pressure turbine inlet valves. The low pressure turbine inlet valves are further grouped into reheat stop valves and intercept valves. The low pressure turbine inlet valves have identical steam path components. The valves differ only by the orientation of the actuators and spring can assemblies. All the turbine valves are exercised and observed at least semiannually.

At least two valves from each of the three turbine valve groups will be removed and replaced with refurbished rotational spares during each refueling outage. The removed valves will be dismantled and inspected during non-outage periods. The non-outage dismantle inspections will as a minimum consist of surface examinations on the disks and stems. These non-outage inspected valves will then be used as rotational spares for the next refueling outage. During the non-outage inspection, if any attribute is found that would cause the valve function to be lost, then plans will be made for the upcoming refueling outage to inspect the other valves of the same group. Valve seats of the removed throttle valves and governor valves will be inspected for flaws during the refueling outage. If any attribute of the governor or throttle valve seats are found that would cause the valve function to be lost, the other remaining throttle and governor valves will be removed and the seats inspected during the same refueling outage. The low pressure turbine inlet valves do not have seats and are designed with some clearance between the disc and valve body. Under this turbine valve inspection schedule, all low pressure turbine inlet valves will be inspected over a four fuel cycle period and all throttle valves and governor valves will be inspected over a two fuel cycle period.

The extraction steam (non-return) valves will be tested weekly for four weeks following a turbine outage, then quarterly thereafter by verifying the free travel of the weighted arm attached to the valve. Disassembly of the extraction steam valves is not considered necessary since their importance to safety does not justify the risks inherent to reassembling a disassembled extraction steam valve after inspection, mechanical defects affecting the function of the valve are readily identified by exercising the valve, and the frequency of exercising the valve is sufficient to provide confidence that the reliability of the valve to perform its isolation function is satisfactory.

Various parameters for the turbine generator and accessories are recorded and alarmed in the Control Room and logged on the plant computer. A full complement of controls and instruments are provided in order that the turbine generator may be started, operated, tested, and shut down from the Control Room. Routine testing of the main steam throttle and governor valves, and low pressure turbine inlet valves and a portion of the Mechanical Emergency Overspeed Protective System will be done while the unit is carrying load. A full test of the Mechanical Emergency Overspeed Protective System is conducted after every refueling outage and before the unit is synchronized to the grid. In the post refueling outage test, the turbine is verified to trip from the Mechanical Emergency Overspeed Protective System at the 110% of synchronous speed set point. On line testing of the Mechanical Emergency Overspeed Protective System is conducted by increasing oil pressure behind the centrifugal trip weight until the weight releases and strikes the trip latch. The mechanical overspeed trip mechanism is defeated during on-line testing. The functional verifications of the electrical overspeed protection system are conducted with the plant both on-line and off-line. On-line functional verifications consist of periodically simulating an overspeed condition at the turbine trips test panel and verifying the Automatic Stop Trip (AST) solenoid valves open. Off-line functional verifications consist of speed pick-up calibrations and a verification that a simulated overspeed signal will develop a trip signal from the emergency trip cabinet. Off-line functional verifications are conducted every refueling outage. The Overspeed Protection Controller (OPC) solenoid valves are verified functional during each refueling start-up by energizing each one open independently and verifying the turbine valves close. To further ensure the trip solenoid valves remain functional, the valves are replaced with new ones on a periodic basis per applicable plant procedures.

10.2.4 EVALUATION

The steam generators provide a barrier between the primary reactor coolant system and the secondary coolant loop. Therefore, steam supplied to turbine generators is normally expected to be free of radioactivity. Potential leaks in the steam generator tubes and surfaces, coincident with failed reactor fuel are the only potential source of radioactivity in the steam.

In the event of primary-to-secondary system leakage (due to steam generator tube leakage) it is possible for the steam and power conversion system to become radioactively contaminated. A full discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentrations of radioactive contaminants, means of detection of radioactive contamination, anticipated releases to the environment, shielding and access requirements, and limiting conditions for operation, are included in Chapters 11 and 12.

Discussion of the turbine's overspeed protection devices is included in Section 10.2.2. Inspections of turbine valves which are essential for overspeed protection will be in accordance with applicable plant procedures.

A failure of high or moderate energy piping in the Turbine Building or at the connection between the low pressure turbine and the condenser has no detrimental effects on safety related systems or components. Should a turbine bypass system pipe fail while the bypass system was active, it may be possible for the ruptured line to impact a hydraulic fluid drain line from the turbine overspeed protection system. However, the loss of overspeed protection would be precluded since the turbine overspeed control system is a redundant system having both mechanical and electrical trip mechanisms. Protection of the components from a high or moderate energy line failure is provided as follows. The normal EHC Overspeed Protection Controller (OPC) speed pickup is located inside the governor pedestal, therefore, well protected against steam or water jets, high temperature and humidity, and pipe whip. Electrical wiring is run in conduit and electrical trays between the governor pedestal, terminal boxes, computer equipment room, and steam valve servo actuators and well separated from the wiring used with other protection systems so that damage which might occur to the wiring of one system should not affect the wiring of other systems. Damage to the connecting wiring would result in closure of the steam valves. A separate Overspeed Trip speed pickup is located in the turning gear housing, well removed from the governor pedestal. The electrical speed signal is transmitted to the computer equipment room in the same manner as the normal EHC OPC signal. In addition, the overspeed trip electrical signal can be manually initiated by a switch on the Main Control Board. The Emergency Overspeed Trip System is entirely hydraulic and is independent of electrical control. The Emergency Overspeed Trip System trip device is enclosed in the governor pedestal and actuates a valve mounted on the governor pedestal to dump the high pressure hydraulic fluid. Although crimping of tubing is conceivable, damage which would prevent timely closure of the steam valves is very unlikely as the hydraulic tubing is run on the inside of the T G concrete pedestal where minimum exposure to high and moderate energy lines is attained. The emergency overspeed trip can be actuated manually via a lever mounted on the outside of the governor pedestal. The redundancy of the three overspeed protection systems, having both mechanical and electrical trip mechanisms, makes the potential for failure of all three a very low probability. In the event of high and moderate energy piping failures the functional capability of the control system equipment will not be impaired.

A description of the protection provided by bypassing and dumping main steam to the condenser and atmosphere in case of sudden load rejection by the turbine generator is included in Section 10.4.4. A description of the protection provided by exhausting steam to the atmosphere through the safety valves in the event of a turbine generator trip and coincident failure of the Steam Dump System is given in Section 10.3.

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 DESIGN BASIS

The Main Steam Supply System (MSSS) is designed to perform the following functions:

a) Deliver steam from the three steam generators (SGs) to the turbine generator at maximum design load (see Figure 10.1.0-7);

b) Remove heat generated by the NSSS in the event the turbine generator is not in service by use of the Steam Dump System, as described in Section 10.4.4 or by relieving to atmosphere through the main steam safety valves, or the power operated relief valves;

c) Provide steam for the moisture separator reheaters (MSRs);

d) Deliver steam to the auxiliary feedwater pump turbine in the Auxiliary Feedwater System (AFS), see Section 10.4.9;

e) Provide steam for the Auxiliary Steam Supply System and

f) Provide steam to the Turbine Gland Sealing System, as described in Section 10.4.3;

g) Isolate the steam generators from the remaining portions of the MSSS and from each other as discussed in the plant accident analyses described in Section 10.3.3 and Chapter 15;

h) Provide extraction steam to the feedwater heaters.

The Main Steam Supply System design conditions and system operating parameters are presented in Table 10.3.1-1.

Seismic classification, safety classification and applicable design codes are presented in Section 3.2.

The following is a summary of the seismic category and safety class design considerations of the Main Steam Supply System:

a) The main steam supply system piping from the steam generator, through the containment penetration, up to and including the main steam isolation valve (MSIV) is designed and fabricated to the requirements of Section III of the ASME Boiler and Pressure Vessel Code, Class 2. This requirement also applies to all branch lines from the safety class portion of the main steam line up to and including the first normally closed shutoff valve on the branch line. The main steam piping, downstream of the main steam isolation valve up to and including the last seismic restraint in the Turbine Building, is stress analyzed to the Class 3 requirements of the ASME B&PV Code, Section III, is Seismic Category I and is designed and fabricated in accordance with the requirements of the ANSI Power Piping Code B31.1, with a 10CFR50 Appendix B program applied. The piping downstream of the last seismic restraint is designed and fabricated in accordance with ANSI B31.1.

The safety related portions of the MSSS are designed to include suitable access to permit in-service inspection and testing, according to the ASME B&PV Code, Section XI.

The design of the main steam line penetration assemblies is discussed in Section 3.8.2.

a) The steam supply piping to the auxiliary feedpump turbine downstream of the normally closed isolation valve is designed and fabricated to the ASME B&PV Code Section III, Class 3 requirements.

b) The main steam safety valve and power operated relief valve discharge piping up to and including the respective valves is Seismic Category I.

The design of the main steam supply piping also includes the following provisions and considerations:

a) Optimization of the routing and support of the main steam piping and components from the steam generators to the main steam isolation valves in order to limit the loadings resulting during normal operating and upset conditions;

b) Consideration of the dynamic loading associated with closure of the main steam isolation valves outside of the Containment; including the support of the valves;

c) Optimization of the pipe routing and support of interconnected steam piping to the moisture separator reheaters and to the condenser (Steam Dump System) for normal and transient conditions;

d) The design of the steam piping between the steam generators and the turbine provides for even distribution of load between the steam generators. The piping is designed to allow periodic exercise of the turbine main stop valves (one at a time) while the plant is at reduced power, without adverse effect on the Reactor Coolant System;

e) Main steam branch lines are sized to limit the maximum flow in any branch line in order to minimize the consequences of a pipe break or valve failure in that line;

f) Each MSIV is provided with a small diameter bypass line for warmup and/or pressure equalization of the downstream piping;

g) The MSSS includes adequate provisions so that no consequence of a postulated system pipe rupture shall jeopardize the redundancy/integrity of any system required for safe plant shutdown or the habitability of the Main Control Room. See Section 3.6 for further discussions on the design basis for pipe rupture considerations;

h) Protection against external or internal missiles is described in Section 3.5;

i) The environmental design bases for the safety related portions of the main steam supply piping and components are defined in Section 3.11; and

j) All valves are fabricated and tested such that the steam leakage past the valve seat of a closed valve does not exceed the specified limits.

10.3.2 DESCRIPTION

The Main Steam Supply System consists of those piping and valves that extend from the steam generators to the turbine stop valves as shown on Figure 10.1.0-1. Three 32 in. diameter main steam lines, one coming from each of the steam generators, conduct steam to a 50 in. diameter equalizing manifold. Two 44 in. diameter lines leave the manifold. Two 24 in. diameter pipes from each 44 in. steam line in turn transfer steam to the two high pressure turbine stop valve steam chests.

Steam flow from each steam generator is measured across the flow limiter which is provided in the steam generator outlet nozzle to restrict the steam flow from the affected steam generator in the event of a main steam line break. The steam generator design basis is described in Section 5.4.2.

The 32 in. diameter lines from each steam generator are each provided with five main steam safety valves, one electro-hydraulic power operated relief valve, and one main steam isolation valve. The two 44 in. diameter steam lines to the high pressure turbine are provided with a total of eight atmospheric steam dump valves. Each 44 in. line is provided with a 24 in. diameter branch pipe which allows steam to pass to the six steam dump valves discharging to the condenser and with branch connections for the supply of main steam to the single stage moisture separator reheaters.

The steam supply to the auxiliary feedwater pump turbine drive is taken from two of the three 32 in. steam supply pipes upstream of the main steam isolation valves. Isolation valves are installed in the two six in. main steam branch lines to the auxiliary feedwater pump turbine which are normally closed. Safety Class IE DC power is supplied from redundant A and B buses to the two motor operated isolation valves. Each six in. line is also provided with a check valve downstream of the isolation valve in order to assure a continuous supply of steam in the unlikely event of a main steam or feedwater line break inside Containment. See Section 10.4.9 for further details of this portion of the system.

The steam supply to the Turbine Gland Sealing System is taken from one of two 44 inch steamlines downstream of the atmospheric dump valves. The steam supply to the Auxiliary Steam and Condensate System is taken from the other 44-in. steamline downstream of the atmospheric dump valves. Isolation and pressure control valves in the main steam supply line to the auxiliary steam headers are normally closed and remotely controlled.

For each flow path of branches off the main steam lines between the MSIV's and the turbine stop valves, Table 10.3.2-1 provides the following design information:

a) System Identification - branch off flow path

b) Maximum Steam Flow

c) Type of Shut-off valve(s)

d) Size of Valve(s)

e) Quality of Valve(s)

f) Design Code of Valve(s)

g) Closure Time of the Valve(s)

h) Actuation Mechanism of the Valve(s)

i) Motive or Power Source

Leakage detection is provided to initiate MSIV closure in case of a steam line break.

10.3.2.1 Main Steam Isolation Valves

One MSIV is located in each 32 in. main steam supply line downstream of the main steam safety valves and power-operated relief valve, and as close to the Containment Building as practical. The valve is designed to stop flow from either direction when it is tripped closed. A small bypass valve is provided to permit equalizing steam pressure across the main steam isolation valve before reopening following a trip, or during startup for the purpose of main steamline warmup.

The MSIVs are held in the open position by instrument air which exerts pressure on the bottom of the piston actuator. Spring pressure on the piston actuator acts as the driving force for valve closure. The MSIVs close within five seconds upon de-energizing the solenoid valves. To assure safety function actuation, redundant actuation solenoid vent valves, powered from separate IE power sources, open to vent air from the bottom of the piston actuator through two separate vent lines. See Section 7.3 for further discussions on the Engineered Safety Features Actuation System.

The MSIVs are fully open during power operation. They are required to limit uncontrolled flow of steam from the SGs in the event of a break in the steam piping system. The design criteria for the MSIVs are:

a) They are designed to Seismic Category I, Safety Class 2, requirements.

b) They must close within five seconds upon receipt of signal with or without steam flow. The valve is designed to stop forward flow and reverse flow.

c) They are a fail-closed design. Loss of instrument air will close the MSIVs.

d) They are installed in the individual MS lines to prevent that SG from blowing down on a break downstream of the valve.

e) They are installed in the individual MS lines to prevent Containment overpressurization from reverse flow on a break inside Containment.

10.3.2.2 Main Steam Safety Valves

Each main steam supply line is provided with five spring-loaded safety valves designed and installed to the requirements of ASME B&PV Code Section III, Class 2. The safety valves are located outside of the Containment between the containment penetration and the MSIV.

To avoid lifting during pressure transients, set pressures for the safety valves are as high as possible within the code requirements. To prevent chattering during operation of the safety valves, the individual valves in each steam supply line are set at a different pressure. The lowest safety valve set pressure is based upon the steam generator design pressure (1200 psia) plus accumulation and less the line pressure drop. Table 10.3.1-1 summarizes the design parameters for the main steam safety valves.

During outages the MSSV's may be removed and blind flanges temporarily installed to maintain containment closure while in Mode 5 or 6. This is required to facilitate maintenance on the safety valves.

10.3.2.3 Main Steam Power-Operated Relief Valve

Each main steam supply line is provided with one power-operated relief valve, located outside the Containment between the containment penetration and the MSIV. The power operated relief valve is provided in order to permit the removal of heat from the Nuclear Steam Supply System during periods when the main steam isolation valves are closed. In addition, the power-operated relief valve set pressure is between the zero load steam pressure and the set pressure of the lowest set safety valve. This configuration prevents operating the safety valves during mild transients and following safety valve actuation, act to assist the safety valves to positively reseat by automatically reducing and regulating the steam pressure to a value below the safety valve reseating pressure.

The operation of the power-operated relief valves is automatically controlled by steamline pressure during plant operations. The relief valves automatically open and exhaust to the atmosphere whenever the steamline pressure exceeds the opening setpoint. During a SGTR event, the Emergency Operating Procedures provide the Control Room operators with guidance for the ruptured steam generator relief valve remote manual setpoint adjustment.

The relief valves (in conjunction with the Auxiliary Feedwater System) allow the plant to be cooled from the pressure setpoint of the lowest set safety valves down to the point where the

Residual Heat Removal System (RHRS) can assume the burden of heat removal. Residual heat removal operations are initiated when the reactor coolant system indicated hot leg temperature has reached 350 F and indicated primary coolant pressure is less than or equal to 363 psig. The 350 F RHR cut-in point corresponds to a steam generator steam pressure of 125 psia if reactor coolant pumps are operated, or to 100 psia if only natural circulation conditions exist in the primary system.

For their use during plant cooldown, the power-operated relief valves are manually controlled or automatically controlled by steamline pressure with remote manual adjustment of the pressure setpoint from the Control Room. In order to affect a plant cooldown, the operator in the Control Room manually adjusts the pressure setpoint downward in a stepwise fashion. As the pressure setpoint of the relief valves is adjusted downward, the relief valves will initially open wide to reduce the steam generator saturation temperature and pressure. As the pressure and temperature begin to decrease, the relief valve opening will decrease to an area sufficient to pass the decay heat load and maintain constant steam pressure until the pressure setpoint is again manually reduced. The frequency of these readjustments by the operator and the magnitude of the step reductions (together with the auxiliary feedwater flowrate) determine the average cooldown rate. The maximum cooldown rate achievable is ultimately limited, however, by the flow passing capability of the relief valves, the number of steam generators (and hence the number of relief valves) in service, the available auxiliary feedwater pumping capacity, as well as by the desire to either maintain or recover steam generator water levels during the cooldown.

The relief valve capacities listed in Table 10.3.1-1 are sufficient to permit cooling the plant from the zero load hot standby temperature down to the temperature corresponding to a steam generator pressure of 100 psia over a period of approximately five hours duration at an average cooldown rate of approximately 50 F/hr, beginning at two hours following a reactor trip. The capacity for a five hour cooldown subsequent to a two hour hot standby period is consistent with the requirements of the auxiliary feedwater supplies as discussed in Section 10.4.9.

After several strokes following loss of electrical power, valve operation may require local action.

10.3.3 EVALUATION

The failure of any main steam supply line or malfunction of any active component installed therein or any consequential damage will not:

a) reduce the flowrate of the Auxiliary Feedwater System below the minimum required for safe plant shutdown;

b) render inoperable any Engineered Safety Feature;

c) initiate a loss-of-coolant accident;

d) result in a containment pressure exceeding the design value;

e) cause an uncontrolled flow from more than one steam generator or violate the integrity of the Containment Building.

A single malfunction or failure of an active component will not preclude safety related portions of the system from functioning as required during normal operations, adverse environmental occurrences, and accident conditions, including loss of offsite power.

Analyses for postulated accidents involving the MSSS are provided in Chapter 15. The seismic design of the MSSS is discussed in Sections 3.2 and 3.7. Loading combinations and design stress limits relating to the safety related portions of the MSSS piping are listed in Section 3.9. Postulated high-energy line failures and protection considerations for the MSSS are discussed in Section 3.6.

All safety related components in the MSSS are designed to perform their intended function under normal and accident temperature, pressure, humidity, chemical, and radiation environment to which they will be subjected. Environmental design bases and qualifications are discussed in Section 3.11.

The main steam isolation valves cannot be tested during normal operation without causing severe system transients. Therefore, they are provided with an exercise mode which allows the valves to be cycled from full open to 90 percent open and back to full open during power operation. The partial stroke exercise is a capability and not a requirement. Full-scale testing of the actuation system is accomplished during scheduled plant shutdown periods. Redundant solenoid valves are provided so that the MSIV can still close with the failure of any one solenoid valve.

All ASME Code class 2 and 3 main steam piping is furnished with removable insulation to allow in-service inspection of the welds.

The failure of non-Seismic Category I piping, equipment, and components will not preclude essential functions of the safety related portions of the system.

In all of the secondary system pipe rupture analyses considered, no credit is taken for "non-safety grade" systems, components and structures to mitigate the consequences of the postulated accident.

As described in Issue No. 1 of NUREG-0138, one postulated steam line break accident that the staff has suggested taking credit for all valves downstream of the MSIVs is the rupture of a main steam line inside containment resulting in the blowdown of the affected steam generator. If an additional failure occurs, and if no credit is taken for "non-safety grade" valves functioning following this assumed event, a second steam generator rapid depressurization would occur. Specifically, the following accident scenario is one that has been suggested by Issue No. 1:

a) A rupture occurs upstream of the MSIV in one of the main steam supply lines.

b) A safety grade MSIV associated with one of the intact steam generators fails to close on demand.

c) In addition, the non-safety grade valves, such as turbine stop valves and control valves upstream of the turbine, or the turbine bypass valve fail to close on demand, providing a path for blowdown of a second steam generator.

This scenario exceeds the occurrences assumed under the single failure criteria and consequently has not been considered as a design basis for the plant. NUREG-0138 acknowledges the fact that the probability of blowing down more than one steam generator as a result of the accident scenario described above is quite low. The Staff concluded in a survey of the operating experience of the turbine stop, control, and intercept valves in operating PWRs, the reliability of these valves is of the same order of magnitude as that accepted for nuclear safety-grade components.

In addition, each branch line between the MSIVs and turbine stop valves is equipped with valving such that either remote operation (closure) of the valve from the main control room is possible or manual shut off of the valve is available. Each motor and diaphragm operated valve can also be closed manually at the valve in the unlikely event that power or air is lost.

Based upon the above no special design features have been provided for "non-safety grade" components and this particular scenario has not been considered as a design basis accident.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

The nuclear safety-related portions of the main steam line piping were built and tested in accordance with the ASME Boiler and Pressure Vessel Code Section III, Subsection NC 6000. Main steam line thermal expansion and dynamic effects testing is described in Section 3.9.2.1. The preoperational and start-up tests of the Main Steam Supply System are discussed in Section 14.2.12. Periodic tests as required by the Technical Specifications will be performed. The MSIVs, main steam safety valves, and main steam power operated relief valves are included in the Pump and Valve Testing Program described in Section 3.9.6.

Pre-service and in-service inspection requirements for the safety related portions of the Main Steam Supply System are contained in Section 6.6.

10.3.5 WATER CHEMISTRY

Bulk water impurities of the FW secondary side and SG systems are kept at a minimum in order to avoid potential corrosion or scaling problems, and to ensure efficient heat transfer.

10.3.5.1 Chemistry Control Basis

Secondary water chemistry is controlled by the following methods:

1. Close control of the condensate and FW purity by means of impurity ingress control, and when necessary, the use of condensate polishing demineralizers.

2. Reduction of the SG bulk water impurities by blowdown.

3. Chemical addition to reduce general corrosion and to scavenge oxygen.

4. Sampling of the condensate, FW, steam, and SG blowdown to monitor key chemical constituents.

10.3.5.2 Method of Chemistry Control

10.3.5.2.1 Condensate and feedwater chemistry

Chemical feed to the secondary water is based on all volatile treatment (AVT) which involves injection of an amine and hydrazine or equivalent solutions as required to the effluent header of the condensate polishers, the number 5 feedwater heaters' outlets, the moisture separator reheater drain tank inlet or the moisture separator drain tank inlet header. An amine solution is added for establishing and maintaining alkaline pH conditions throughout the secondary cycle. Hydrazine or equivalent solution is added for scavenging dissolved oxygen present in the cycle and maintaining adequate residual concentration to ensure that a minimal amount of dissolved oxygen enters the SG. The use of the AVT method reduces general corrosion and thereby minimizes the transport of corrosion products to the SG. Records and summaries of chemical analyses are maintained.

Removal of oxygen from the secondary water is essential to reduction of corrosion, particularly of carbon steel. Dissolved oxygen is removed from the cycle in the deaerating section of the main condenser and by the use of hydrazine or equivalent as a scavenger.

10.3.5.2.2 Steam generator chemistry

In addition to the use of AVT chemicals and deaeration, blowdown is employed to limit the buildup of contaminants in the SG and maintain acceptable bulk water chemistry. Section 10.4.8 describes the SG blowdown system (SGBS). The Condensate Polishing Demineralizer System (CPDS) described in Section 10.4.6 may also be placed inservice to assist in the control of the secondary water chemistry when needed. Implementation of the above chemistry control procedures to maintain low solid levels is expected to minimize corrosion and scale forming tendencies within the cycle.

10.3.5.2.3 Monitoring and controlling of water chemistry

A secondary water sampling and monitoring program is implemented to establish and maintain appropriate water chemistry conditions in the secondary system. The main objective of the water sampling and monitoring program is to inhibit SG corrosion and tube degradation by assuring chemistry excursions from control limits are quickly identified. The program provides for the monitoring and recording of critical chemistry parameters to assure proper control of water treatment additives, FW purity, and SG bulk water impurities. The water sampling and monitoring program involves both laboratory and continuous on line analysis of secondary samples utilizing the process sample system described in Section 9.3.2. The program complies with the administrative requirements outlined for the Secondary Water Chemistry Program as specified in the Technical Specifications.

Monitoring and controlling of water chemistry will follow the guidance provided in plant procedures, which are based on information provided by the Westinghouse Electric Corporation and by the Electric Power Research Institute. Differences between plant procedures and Westinghouse and EPRI guidelines are evaluated and documented. The plant procedures present a water chemistry program to minimize corrosion in the primary and secondary coolant systems. Also presented is an Action level concept that sets predetermined conditions for identifying when to take corrective action for off normal water chemistry and recommends an action plan. The plant procedures specify sample point location and sampling frequency for the primary and secondary systems.

10.3.5.3 Chemistry Control Effects on Iodine Partitioning

The pH of the secondary water is maintained at a level that causes an increase in the radioiodine partition coefficient, where the partition coefficient is defined as:

$$\frac{\text{grams of iodine/liter of water}}{\text{grams of iodine/liter of vapor}}$$

The greater the partition coefficient the greater the amount of iodine remaining in the condensed water. Therefore, the majority of any radioiodine resulting from the primary-to-secondary leakage will remain in solution in the condensate and be removed by the condensate polishing demineralizer.

10.3.6 STEAM AND FEEDWATER SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

Materials used for Class 2 and 3 components of the Main Steam Supply System and the Feedwater System, non-Westinghouse supplied, were not required to be fracture toughness tested by either the design specification or ASME Section III NC-2300 at the time of award of the piping contract. However, the fracture toughness properties of these materials is considered to be acceptable. Materials used for Class 2 components supplied by Westinghouse have been fracture toughness tested in accordance with the requirements of ASME Section III, NC-2300. Materials used for Class 3 components supplied by Westinghouse were fracture toughness tested in accordance with design specification requirements.

10.3.6.2 Materials Selection and Fabrication

1. Materials for Class 2 and 3 components supplied by Ebasco have been selected from those included in Appendix I to Section III of the ASME Code. The mechanical properties of materials specified for use on Class 2 and 3 components are in conformance with the requirements of ASME II, Parts A and/or C.

2. The extent of compliance of Westinghouse-supplied components with applicable Regulatory Guides is described in Section 1.8. For austenitic stainless steel components supplied by Ebasco, the degree of conformance to the recommendations of applicable Regulatory Guides is as follows:

    a) Conformance to Regulatory Guide 1.44

        1) All seamless stainless steel pipe and fittings, electric arc welded stainless steel plate pipe and fittings, and stainless forged materials, are purchased in the solution annealed condition. Manufacturers are required to control the temperature, holding time, and cooling rate so that the material can be accepted under the Practice E of ASTM A-262-70, "Copper-Copper Sulfate-Sulfuric Acid Test" and to optionally screen the material by Practice A, the "Oxalic Acid Etch Test." The tests are performed on a production basis for

pipe and fittings which are greater than two inches in wall thickness or which are not quenched in water. One test per heat for each heat treatment lot is required.

2) All castings are solution heat treated. Manufacturers are required to test materials in accordance with Practice E of ASTM A-262-70, "Copper-Copper Sulfate-Sulfuric Acid Test" optionally screened by Practice A, the "Oxalic Acid Etch Test." The test is performed on a minimum of one test per heat for each heat treatment lot of a given casting configuration. Castings contain a minimum of five percent ferrite as determined by test report chemical analysis applied to the Schaeffler Diagram or by metallographic means.

3) All stainless steel components are cleaned, and descaled in accordance with the recommended practices of ASTM A380, which will protect against contaminants capable of causing stress corrosion cracking. Pickling is not performed on sensitized stainless steel.

4) Base metal is cleaned prior to and after welding to remove contaminants capable of causing stress corrosion cracking. Grinding wheels and brushes used are used only on stainless steels.

5) Welding practices are controlled to avoid severe sensitization. Weld test samples from new procedure qualification test welds, or weld samples using the qualified procedure, are required to be subjected to non-sensitization testing in accordance with ASTM A-262-70, Practice A or E. The maximum interpass temperature is specified to be 350 F.

b) Conformance with Regulatory Guide 1.36 - The composition of nonmetallic thermal insulation for austenitic steel components is controlled in accordance with Regulatory Guide 1.36, as described in Section 1.8.

c) Conformance with Regulatory Guide 1.31 - The delta ferrite content of welds in austenitic stainless steel procured components of the Class 2 steam and feedwater systems is controlled, as a minimum, in accordance with the essential requirements of Regulatory Guide 1.31, Revision 1, June 1973. The extent of compliance is as follows:

1) Austenitic stainless steel filler metals are purchased to the acceptance test requirements of Sections III of the ASME Boiler & Pressure Vessel Code. Purchase orders specify an additional requirement, that austenitic stainless steel filler metals, other than SFA-5.4, Type 16-8-2, conform to an analysis demonstrating that a minimum of five percent ferrite be present in undiluted weld deposits.

2) Flux bearing filler metals are tested for ferrite yield by chemical analysis using material obtained from all weld metal test samples. Bare filler metals, to be deposited by inert gas shielded processes, may have ferrite yield predicted from wire analysis. The analyses are applied to the Schaeffler Constitution Diagram for ferrite determination.

3) All weld metal test samples, required for flux bearing filler metals, are produced according to the method described in ASME Specification SFA-5.4. The acceptable ferrite range for all filler metals is five percent minimum. ASME SFA-5.4, Type 16-8-2 is excluded from this requirement.

4) The filler metal supplier makes chemical analysis tests, using material samples as required by the filler metal type. The analytical results are applied to the Schaeffler Constitution Diagram for ferrite determination.

5) The results of required analytical tests are included in a Certified Materials Test Report, per the requirements of the ASME Code, Section III, NB-2130. The results of the ferrite determination are also included in the Certified Test Report.

6) A delta-ferrite determination was made on weld deposits of selected vendor production welds using calibrated magnetic measuring devices conforming to AWS A4.2-74, "Calibrating Magnetic Instruments to Measure the Delta-Ferrite Content of Austenitic Stainless Steel Weld Material." A representative number of stainless steel welds of wall thickness greater than one inch have been tested for ferrite content.

The weld joints were examined in the weld center at 90 degree intervals of circumference and are required to show an average ferrite content of no less than three percent. Furthermore, no single reading was below one percent ferrite.

The results of this sampling examination has proven the CP&L hypothesis that actual ferrite measurement of production welds is unnecessary, provided the requirements of Paragraphs 3(a) - 3(e) above are adhered to.

Components procured after the issuance of Regulatory Guide 1.31, Revision 2 (May 77), and Revision 3 (April 78) comply in full with the above or the applicable revision of the Regulatory Guide. For field fabrication, the requirements of Regulatory Guide 1.31, Revision 3 (April 78) are complied with for Code Class 2 and 3 work.

3. The procedures for cleaning and handling of Class 2 and 3 components of the steam and feedwater systems are in compliance with Regulatory Guide 1.37 as described in Section 1.8.

4. Control of preheat temperatures for welding carbon and low-alloy steels in components supplied by Ebasco complies with Regulatory Guide 1.50 as follows:

   a) When used, low-alloy steels will be pre-heated as required by the Regulatory Guide, unless exceptions noted within the Regulatory Guide apply (e.g., Volumetric Examination).

   b) Vendor's welding procedure specifications for carbon steels specify the preheat and interpass temperatures to be in accordance with the recommendations of ASME Section III, Article D-1000.

c) All flux-bearing filler metals are specified to be low-hydrogen type.

d) Vendors are required to store all low-hydrogen electrodes in ovens at 200-300 F for eight hours following their removal from containers and prior to use.

e) Production welding is monitored by quality control personnel to verify that specified limits on preheat and interpass temperature are maintained.

5. For all Class 2 and 3 components, welder qualification for areas of limited accessibility complies with the recommendations of Regulatory Guide 1.71 as described in Section 1.8.

6. Class 2 and 3 steam and feedwater system components comply with the requirements of the ASME Boiler and Pressure Vessel Code, Summer 1972 or Summer 1973 Addenda.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

10.4.1.1 Design Basis

The main condenser is designed to function as the steam cycle heat sink and collection point for the following flows:

a) Main turbine exhaust;

b) Main turbine last stage moisture removal drains;

c) Condensate, condensate booster and steam generator feedwater pumps minimum flow recirculation;

d) Steam Dump System;

e) Condensate makeup;

f) Feedwater heater, drains and vents;

g) Steam generator blowdown;

h) Main and extraction steam piping drains;

i) Gland steam condenser condensate.

Design data of the main condenser at normal full-load operation of the plant is shown in Table 10.4.1-1.

The main condenser is also designed to:

a) Condense up to 40 percent of the full load main steam flow bypassed directly to the condenser by the Steam Dump System. The steam flow is divided equally between the two condenser zones during steam bypass operation. This condition could occur in case of a sudden load rejection by the turbine-generator, a turbine trip or during start-up and shutdown, as described in Section 10.4.1.3;

b) Provide for removal of noncondensible gases from the condensing steam through the Main Condenser Evacuation System as described in Section 10.4.2;

c) Deaerate the condensate before it leaves the condenser hotwell;

d) Include supports for Low Pressure Feedwater Heaters Nos. 1A and 1B in the Condenser Neck.

The main condenser is constructed in accordance with the guidelines provided in the Heat Exchangers Institute "Standards for Steam Surface Condensers," Sixth Edition, 1970, and is designed to minimize air leakage. The condenser is a one shell, two zone unit employing a transverse partition. The partition is welded around its full circumference thus sealing one zone from the other. Equipment and piping connected to the condenser shell are designed to minimize air leakage to the condenser.

10.4.1.2 System Description

The main condenser is a single shell, multipressure, two zone deaerating surface condenser. The condenser is a divided waterbox, single-pass type with the condenser tubes oriented parallel to the turbine shaft. Cooling water for the condenser is provided by the Circulating Water System. The condenser is sized to condense exhaust steam from the main turbine under full-load conditions.

The condenser can accept up to 40 percent of steam generator rated steam flow in the event of an electrical load drop in excess of 10 percent without exceeding maximum turbine back pressure of 8.0 inches Hg abs, as specified by the turbine manufacturer.

Condenser hogging and vacuum holding is accomplished by two mechanical vacuum pumps. The condenser is a deaerating type, which removes dissolved air and other noncondensible gases from the condensate, during all modes of operation. Removal of these gases is discussed in Section 10.4.2.

The condenser hotwell provides storage capacity to allow system inventory to vary during operating transients and supplies condensate to the condensate pump suction connections. The hotwell storage capacity of 11,290 cubic feet is sufficient for approximately five minutes of full load operation between normal and low water levels. Condenser level is automatically maintained by makeup from the Condensate Storage System (see Section 9.2.6), from which condensate is caused to flow by atmospheric pressure, gravity, or condensate transfer pump head, into the condenser. The automatic makeup is performed through a level control valve which receives a low water level signal from the condenser. There is a manually operated bypass valve around this level control valve for backup, startup filling, and freeze protection. For high water level in the hotwell during normal plant operation, separate piping with a level control valve is provided from the condensate pump discharge to the condensate storage tank. The controls for the condenser level control system are monitored from the common hotwell in the area of Condenser Zone 2. The system flow diagram showing connections to the condenser is presented on Figure 10.1.0-4.

In order to reduce impurity ingress into the steam/condensate system in the event of tube to tubesheet joint leakage, the condenser is provided with integral grooved tube sheets (IGTS) which are filled with condensate maintained at a pressure above circulating water system pressure. This is accomplished during manufacture by boring an annular groove in each tube hole midway through the tube sheet. The outside diameter of each groove is selected such that each groove overlaps its adjacent grooves, thereby providing a communicating flow path to every tube to tubesheet joint location. The tubesheet is then drilled at three points on its external surface in order to provide external access to the network of grooves. These points are then piped to a condensate water supply from the IGTS pressurization tank. The result is that in the event of a tube to tubesheet joint leak, condensate, rather than circulating water, enters the condenser shell. This system is shown on FSAR Figure 10.2.2-6.

Valves are provided in the Circulating Water System to permit either half of the condenser to be isolated for condenser tube maintenance. Level gauge glasses are provided for visual observation of hotwell water level.

The condenser is connected to each turbine low pressure outlet connection by means of a flexible rubber expansion joint which is protected internally against steam flow by means of an impingement plate.

Baffle plates and sparger pipes are provided inside the condenser shell to disperse the energy from drain flows and steam dump to avoid damage to condenser tubes due to impingement of such flows.

The top row of tubes in the upper tube bundles were plugged during installation in order to provide a sacrificial barrier against the effects of steam impingement and debris impact. In addition, high energy shell connections (i.e. pump recirculation lines) are fitted with impingement baffles.

10.4.1.3 Safety Evaluation

The main condenser provides a load for the steam generators during plant start-up, hot-stand-by, and cooldown to enable the NSSS to follow turbine load reductions. This load is created by dumping steam from ahead of the turbine stop valves to the condenser and/or atmosphere, (See Section 10.4.4).

In the event that the condenser loses its condensing capability during a sudden full external electrical load drop, the main steam safety valves will discharge to atmosphere.

The condenser is not required for safe shutdown of the plant, and there is no direct influence of the condenser operation on the operation of the primary reactor coolant system. However, the loss of condenser vacuum control function will cause a turbine trip and subsequently a reactor trip; therefore, the loss of a condenser vacuum control function will indirectly impact the RCS. The effects of a turbine trip on the reactor coolant and secondary systems are analyzed in Chapter 15. Non-availability of the condenser includes loss of circulating water with resultant loss of condenser vacuum or other circumstances which would prevent the use of the condenser.

The permissible cooling water inleakage and time of degraded condenser operation is dependent on the Condensate Cleanup System (Section 10.4.6) which maintains the condensate/feedwater quality within acceptable limits under all modes of plant operation. The Condensate Polishing demineralizers are designed to remove the influent ions present resulting from a 10 gpm circulating water leak into the condenser. At this rate the exhaustion rate of a single demineralizer is more than 100 hours, which is well above the demineralizer regeneration time of approximately 20 hours. Failure of the Condensate Cleanup System to perform this function will not affect safe shutdown of the plant.

Under normal operation and shutdown, the main condensate does not have radioactive contaminants. Radioactive contaminants can only be obtained through primary-to-secondary system leakage due to a steam generator tube leak. Noncondensible gases will be monitored for radioactivity prior to being discharged to the atmosphere, as discussed in Section 10.4.2.2 (refer to Sections 9.4.2 and 11.5). There is no potentially explosive gaseous mixture present in the Main Condenser Evacuation System during normal operation. No hydrogen buildup in the main condenser is anticipated.

A discussion of flooding resulting from failure of either the condenser or the Circulating Water System is provided in Section 10.4.5.

A discussion of secondary water chemistry limits is provided in Section 10.3.5.

10.4.1.4 Tests and Inspections

Shop hydrostatic tests will be conducted on the condenser water boxes. The condenser shell is vacuum and hydrostatically tested after completion of construction. Functional testing verifies proper operation of valves and instrument calibration verifies pressure setpoints. Field tests, when conducted, are governed by the provisions of ASME Power Test Code for Steam-Condensing Apparatus.

The performance characteristics of the main condenser will be monitored on a continuous basis as part of the unit efficiency and reliability program. This monitoring will provide an early indication of the physical status of the system and will provide the basis for determination of the extent of the inspection to be done on a refueling internal basis.

10.4.1.5 Instrumentation Applications

Main condenser instrumentation is shown on Figure 10.1.0-4. Each condenser zone (1 and 2) is provided with a local level gage for level indication. Condenser 1B zone 2 (Hotwell) is also provided with remote level indication and a high and low level alarm in the control room. Condenser zones 1 and 2 are provided with remote pressure indication in the control room. The individual indicators and alarms and their locations are listed in Table 10.4.1-2.

In the event of loss of vacuum, the turbine dump valves to the condenser close automatically. If the dump valves are closed, the signal of vacuum loss keeps them blocked to prevent their opening (see Table 7.7.1 1; interlock C 9).

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The Main Condenser Evacuation System (MCES) shown on Figure 10.1.0-4 is designed to establish and maintain condenser vacuum during plant start-up and shut-down and to remove air and noncondensible gasses during plant operation.

The MCES is non-nuclear safety class and non-seismic Category I. This safety classification corresponds to the Quality Group D classification of Regulatory Guide 1.26.

10.4.2.2 System Description

The system flow diagram is presented in Figure 10.1.0-4. The MCES is a non-nuclear safety, non-seismic Category I system. Condenser hogging and vacuum holding is accomplished by two 100 percent capacity mechanical vacuum pumps and all necessary piping, valves, instruments and electric devices for automatic operation of the system. The MCES mechanical vacuum pumps, piping, valves and strainers are designed to ANSI B31.1 and/or appropriate manufacturer and industry standards. Quality standards for the MCES correlate with Quality Group D of Regulatory Guide 1.26. Energizing the condenser vacuum pump starter automatically starts the seal water system associated with the condenser vacuum pump assembly. The vacuum pumps will not start with inadequate seal water level in their respective separator tanks. As discussed in Section 10.4.1.2 the main condenser is a single shell, multipressure two zone deaerating surface condenser constructed in accordance with the Heat Exchangers Institute "Standards for Steam Surface Condensers," Sixth Edition, 1970. The MCES, consistent with the criteria of the HEI Standard for a condenser shell with two exhaust openings and an effective steam flow for each main exhaust opening of 3,000,001 to 4,000,000 lbs/hr has a design venting capacity of 30 scfm.

Each mechanical vacuum pump of the MCES is designed to the HEI Standard to remove 30 cfm of free dry air at one inch Hg absolute.

During the start-up period, one or two of the condenser vacuum pumps may be used for evacuating a combined turbine and main condenser steam space of 132,090 cubic feet to a pressure of 3 in. Hg abs within a normal period of about 75 minutes using two pumps. Thereafter one pump is needed to maintain a regular condenser pressure.

During normal operation, only one condenser vacuum pump is required. The noncondensible gases and water vapor mixture are drawn directly from the condenser shell. Just before the mixture enters the vacuum pump, inlet spray nozzles condense most of the water vapor. The noncondensible gases are monitored for radiation and then released to the vent stack. A wide range Noble Gas monitor (1TV-3536) is used for monitoring (See Section 11.5.2.7). The monitor's high radiation setpoint is set at a value corresponding to a predetermined primary to secondary leak rate. On high radiation alarm, the operator can initiate operation of the condenser vacuum pump effluent treatment system (CVPETS) and reroute the condenser vacuum pump discharge. The CVPETS is described in Section 9.4.4 and shown along with a radiation monitor on Figure 9.4.4-1. This sequence assures the passage of high activity effluent through a series of HEPA and charcoal filters prior to discharge to the atmosphere via the turbine building vent stack. No hydrogen buildup is anticipated in the condenser. The condensed water from the mechanical vacuum pumps is drained to the industrial waste sumps.

As it is discharged through line 8MD4-119-1, it is monitored through radiation monitor REM 3528 shown in Figure 9.3.3-2 of the FSAR. A description of this monitor is given in Section 11.5.2.5.7.1 of the FSAR. If radioactive contamination is detected, the liquid stream is diverted to the Secondary Waste System in the Waste Processing Building for processing. Normally, one condenser vacuum pump is on standby and is controlled to start up on rising condenser pressure if the running vacuum pump has not tripped.

If the reactor has been shut down for less than 30 days, the condenser vacuum discharge during initial hogging operations at plant startup and prior to turbine operation will be routed via line 7AE-12-9-1 direct to the turbine building vent stack as shown on FSAR Figures 1.2.2-22, 9.4.4-1, and 10.1.0-4. Using this release path, the condenser vacuum pump discharge will have its effluent monitored by noble gas monitor REM-1TV-3534, shown on FSAR Figure 9.4.4-1 and sampled and monitored by the turbine building vent stack monitor described in FSAR Sections 11.5.2.5.11 and 11.5.2.7.2.18. The condenser vacuum pumps discharge radiation monitor, REM-1TV-3534, upon exceeding preset limits, will alarm and alert the operators to an off-normal condition. The operator can actuate valving that will reroute the condenser vacuum pumps discharge and energize the condenser vacuum pump effluent treatment system described in FSAR Section 9.4.4.

If the reactor has been shut down for greater than 30 days, the condenser vacuum pump discharge during initial hogging operations at plant startup and prior to turbine operation may be routed via valve 7AE-B9-1 and line 7AE12-19-1 directly to the turbine building area. This discharge will be monitored by the noble gas monitor, REM-1TV-3534, in line No. 7AE12-9-1 because valve 7AE-B3-1 is a normally open butterfly valve creating dual exit paths for the discharge.

Upon start of turbine operation, the discharge is normally directed to the vent stack directly or through the Condenser Vacuum Pump Effluent Treatment System (CVPETS) if needed.

Gases are sampled and monitored for radioactivity levels downstream of the CVPETS. Any contamination, as monitored by the radiation monitors, will initiate an alarm.

10.4.2.3 Safety Evaluation

The noncondensible gases and vapor mixture discharged to the vent stack and to atmosphere during hogging operation, as described in Section 10.4.2.2, are not normally radioactive. The noncondensible gases and condensed water from the condenser vacuum pump(s) are monitored for radioactivity prior to being discharged to the vent stack and to the industrial waste sump, respectively. The presence of radioactivity would indicate a primary-to-secondary system leak in the steam generator(s). High radiation levels downstream of the CVPETS will cause an alarm. High radiation levels in the condensed water would cause the condensed water to be diverted to the Liquid Waste Processing System, as described in Sections 9.3.3, 9.4.4, 11.2 and 11.5. Low condenser vacuum will cause a turbine trip as discussed in Section 7.7.

There are no potentially explosive gaseous mixtures present in the Main Condenser Evacuation System during normal start up and shut down operations.

10.4.2.4 Test and Inspections

Functional testing verifies proper operation of valves and equipment and instrument calibration verifies pressure setpoints.

The need to test the MCES during normal operation will be minimal since the system will be in use. Preoperational and startup tests are conducted as described in Section 14.2.

10.4.2.5 Instrumentation Applications

A radiation monitor is provided in the MCES noncondensible gas exhaust common header and will alarm on high radioactivity.

Should radioactivity be present in the condensed water, a radiation monitor will cause the valve on the normal discharge line to the industrial waste sump to close and the valve on the line to the Liquid Waste Processing System to open which ensures that there will be no radioactive condensed water discharge into the industrial waste sumps, as described in Sections 9.3.3, 11.2 and 11.5.

Local indicating devices, including pressure and temperature indicators, are provided to monitor system operation. Status indicating lights are provided on the main control board (MCB) for each condenser vacuum pump and its auxiliaries.

The following alarms are provided in the control room for each condenser vacuum pump:

a) Low-low seal water level (alarm shared by both pumps)

b) Vacuum pump trip

c) Hogging valve open (computer alarm)

d) High seal water temperature (computer alarm)

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Basis

The Turbine Gland Sealing System (TGSS) is designed:

a) to prevent air from entering the shaft seals of the turbine casing and entering the condenser.

b) to prevent steam at pressures higher than atmospheric, from leaking along the main turbine shaft to the atmosphere.

c) to collect leakoff fluid from steam control components.

10.4.3.2 System Description

The system flow diagram is given on Figure 10.1.0-1.

The TGSS controls the steam pressure to the turbine glands to maintain adequate sealing under all conditions of turbine operation. The system consists of individually controlled diaphragm operated valves, relief valves and a gland steam condenser. The sources of the steam for the TGSS are the main steam header upstream from the turbine stop valves during normal operation and the auxiliary steam header during startup. During turbine operation seal steam from the high-pressure turbine seals is used to seal the low pressure turbine seals or is discharged to the main condenser.

Each of the low pressure turbine glands has a gland steam supply regulator and is supplied from the gland seal steam header; similarly both high pressure turbine glands are supplied via one regulator. A spill-over valve in the high pressure turbine gland seal piping provides pressure regulation and allows dumping of excess turbine gland leakage to the main condenser.

At start-up, the sealing steam is supplied either from main steam or auxiliary steam source (i.e., the auxiliary boiler). When sufficient pressure has been established in the main steam header, the auxiliary steam source valve is closed and main steam provides sealing. As the turbine load is increased, the steam leakage path is outward toward the rotor ends, thus eliminating the need to supply sealing steam to these glands. The leak-off steam and air mixture then flows to the gland steam condenser which is maintained at a pressure slightly below atmospheric so as to prevent escape of steam from the ends of glands. To prevent air from entering the shaft seals of the low pressure turbine, sealing steam at a pressure greater than atmospheric pressure is introduced into the gland labyrinths. To prevent steam leakage to the atmosphere the low pressure turbine sealing steam leak-offs are piped to the gland steam condenser. The gland steam condenser returns seal leakages to the main condenser as condensate. The condensate flow from condensate pumps serves as a coolant for the gland steam condenser. Vacuum is maintained with either one of two 100 percent capacity blowers in operation. The blowers discharge the non-condensible gas flow directly to the Turbine Building Vent Stack.

The TGSS is non-nuclear safety class and non-Seismic Category I. This safety classification corresponds to the Quality Group D classification of Regulatory Guide 1.26.

10.4.3.3 Safety Evaluation

The TGSS utilizes three sources of sealing steam: HP turbine leakoff, main steam or auxiliary steam. The design of the diaphragm operated valves is such that the failure of any valve will not endanger the turbine. The supply valves fail open on loss of air and the spill-over valve closes. Should such a condition occur, the system safety valves limit the maximum header pressure to a safe value.

Failure of one blower automatically starts the second blower. Should the gland steam condenser fail to function, sealing steam is allowed to flow out of the glands and into the Turbine Building. The gland steam condenser is not considered to be a principal source of radionuclide release. The gland steam condenser exhaust is routed to the turbine building vent stack as shown on Figure 10.1.0-4. The turbine building vent stack is monitored by a wide range noble gas monitor described in Section 11.5.2.7.2.18. No explosive mixtures are anticipated.

Failure of the TGSS high energy piping has no detrimental effect on safety related systems or the Turbine Speed Control System.

10.4.3.4 Tests and Inspections

The gland steam condenser was cleaned, inspected and tested at the vendor's plant prior to startup.

Functional testing of equipment included a hydrostatic test with visual inspection of welded joints to confirm leak tightness. All equipment and controls were calibrated and functionally tested in accordance with available manufacturer's recommendations.

The system is normally in operation when the plant is operating and thus special tests are not required to insure its operability.

10.4.3.5 Instrumentation Application

The TGSS requires manual initiation. Once started, the system is designed to function automatically during all phases of plant operation from plant start up to full-power conditions. The auxiliary steam supply valve automatically regulates the supply of auxiliary steam to the sealing system in the event that main steam is not available at sufficient pressure to seal the turbine. Local manual controls are provided in case of failure of any automatic controls in the systems. The normal feed block valve, the normal feed bypass valve, the main spillover block valve, and the spillover bypass valve, have provisions for remote manual operation, with status indicating lights in the Control Room. Local monitoring equipment is provided to indicate process parameters and equipment performance.

10.4.4 STEAM DUMP SYSTEM

The Steam Dump System (SDS) reduces the magnitude of transients on the NSSS following large load reductions.

10.4.4.1 Design Bases

The Steam Dump System is designated to perform the following functions:

a) To permit the plant to accept sudden load rejections up to 50 percent external electrical load without incurring a reactor trip or lifting the main steam safety valves.

b) To remove stored energy and residual heat from the primary system following a turbine/reactor trip.

c) To maintain the plant in hot stand-by condition.

d) To permit manual controlled cooldown of the plant to the point where the Residual Heat Removal System can be placed in service.

The Steam Dump System has no safety related function.

The dump valves were provided by Westinghouse as ASME B&PV Section III, Class 2, but are used in an NSS application. All other piping and components are designed to ANSI B31.1 requirements.

Steam dump system piping and instrumentation is shown on Figure 10.1.0-1.

Design data is given in Table 10.4.4-1.

10.4.4.2 System Description

The Reactor Control Rod System is designed to automatically control the reactor in the power range between 15 and 100 percent of rated power and can accept the following transients without reactor trip:

a) plus or minus 10 percent step load change

b) five percent per minute ramp load increase or decrease.

Since the NSSS response time is much longer than the turbine response time an energy mismatch occurs. A large energy mismatch can quickly cause a reactor temperature and pressure increase with the associated reactor trip.

The Steam Dump System provides an artificial load by dumping steam to the condenser and atmosphere depending on the size of the load drop. The system was originally designed to permit a sudden load drop up to a maximum of 100 percent external electrical load without tripping the reactor or lifting the main steam safety valves. However, this requirement is no longer the design basis.

The system consists of eight atmospheric steam dump valves which dump steam directly to atmosphere and six condenser steam dump valves which allow steam to bypass the turbine and dump to the condenser. Depending on the vessel full power average temperature, the capacity of the steam dump to the condenser is approximately 29 to 37 percent of rated steam flow. The atmospheric dump valves provide additional capacity, allowing a 50 percent external electrical load drop without tripping the reactor or lifting the main steam safety valves.

All steam dump valves are connected to the main steam piping downstream from the main steam isolation valves. Isolation of the steam dump valves is permissible as the steam dump system is not essential to the safe operation of the plant.

Each dump valve is sized so that the total steam dump capacity is 40 percent of the maximum main steam flow with any one steam dump valve being out of operation. This is sufficient to support a 50 percent electrical load rejection.

The steam dump to the condenser is distributed in a manner to minimize the effect on the condenser pressure and consequently the low pressure turbine backpressure.

The basic function of each steam valve is to modulate the flow of steam.

The steam dump functional tasks are accomplished by either temperature or pressure control signals, measured respectively, in the reactor coolant loop and main steam line.

The temperature control is used during plant operation. When a load drop in excess of 10 percent is indicated the Steam Dump System is activated. In this event the number of dump valves to be opened is determined by the magnitude of the load drop after which the valves are modulated closed as the average temperature (T_{avg}) approaches the reference temperature (T_{ref}). Similarly on a turbine trip, T_{avg} is compared to no load T_{ref} and the temperature error signal is used to control the steam dump valves.

The pressure mode of control is used during hot stand-by, synchronization of the Unit and plant cooldown.

a) During hot stand-by, the main steam line pressure is used to maintain a constant reactor coolant system temperature by modulating the condenser dump valves.

b) Synchronization of the unit requires initial step loading of from 5 - 10 percent step load and the pressure mode is used to maintain stable plant conditions when the step load change occurs.

c) During Unit shutdown, main steam condenser dump valves can be remote manually positioned to remove reactor coolant system sensible heat and reduce the reactor coolant temperature. Since steam pressure decreases as the system temperature is reduced, condenser dump valves are opened to complete the cooldown at the design rate until the Residual Heat Removal System can be initiated.

Inadvertent opening of the dump valves can result in a plant trip or initiate uncontrolled cooldown. Therefore the valves are designed to fail closed on loss of air or loss of signal. In addition, redundant solenoid valves are provided to vent the actuating air upon receipt of a Lo-Lo T_{avg} block signal from the protective system.

For operational purposes the steam dump valves are separated in four groups: two banks of three valves each discharging to the condenser and two banks, one with three the other with five valves discharging to atmosphere.

During plant cooldown, signals actuating the dump valves are blocked with the exception of those condenser dump valves which are required for plant cooldown. Steam dump to the condenser is blocked upon high condenser pressure or when the circulating water pumps are tripped.

In the event of failure of the Steam Dump System due to either a valve in the open position or a line rupture, the resulting steam discharge can be arrested by closing the main steam isolation valves.

10.4.4.3 Safety Evaluation

The Steam Dump System is not essential to safe operation of the plant and is designed to non-nuclear safety classification. The Steam Dump System is not required for cooling the reactor during emergencies.

Failure of the steam dump system high energy line has no detrimental effect on safety related systems. The turbine overspeed control system is a redundant system having both mechanical and electrical trip mechanisms. In the event of a failure in the steam dump system high energy lines the functional capability of the control system equipment will not be impaired. A component failure mode and effects analysis is presented in FSAR Table 10.4.4-2.

10.4.4.4 Tests and Inspections

The Steam Dump System is tested during the preoperational and start up test programs described in Section 14.2.12. The Steam Dump System shall be tested during every refueling outage by remotely stroking the eight atmospheric and six condenser steam dump valves described in Section 10.4.4.2 and by observing the valve position indicator.

10.4.4.5 Instrumentation Application

Other than described in Sections 10.4.4.2 and 10.4.4.3, the control scheme for the steam dump valves are discussed in Section 7.7.

10.4.5 CIRCULATING WATER SYSTEM

10.4.5.1 Design Basis

The Circulating Water System (CWS) provides the main condenser with a continuous supply of cooling water for removing the heat rejected by the main turbines. The system is designed to operate continuously throughout the year under various ambient weather conditions. The system is schematically shown on Figure 9.2.1-2. In addition, the system serves as the preferred heat sink for normal reactor cooldown to 350 F, but has no safety function.

The Circulating Water System includes the following major components:

a) A main condenser

b) A natural draft hyperbolic cooling tower to serve as the heat sink

c) The cooling tower basin

d) Three 33-1/3 percent capacity circulating water pumps

e) A chlorination station for circulating water treatment

f) A makeup water system

g) The required piping, valves, expansion joints and instrumentation.

10.4.5.2 System Description

The Circulating Water System supplies 487,600 gpm of cooling water to the condenser.

Cooling water, at a design temperature of 95.2° F (corresponding to design ambient condition of 95°F DB, 77°F WB and 50% RH), is routed from the cooling tower basin to the circulating water pump intake structure. The intake chamber's depth and width are sufficient to provide low velocity and adequate submersion to ensure maximum pump performance. Individual bays, with a baffle in front of the intake, are provided for each pump to exclude the adverse effects of vortices and to provide a proper flow path and suction velocity.

The circulating water pump intake structure is shown in Figures 10.4.5-1 and 10.4.5-2.

The circulating water pumps discharge the water through individual steel pipes into the CWS pump discharge header. Two 120 inch reinforced concrete pipes carry the water from this distribution header to the Turbine Building. Inside the building two 108 inch reinforced concrete pipes and then two 108 inch steel pipes carry water to the condenser inlet water box. Warm water from the condenser is carried through two 108 inch steel pipes and then two 108 inch reinforced concrete pipes (inside the Turbine Building), to two 120 inch reinforced concrete pipes, which discharge to the hot water distribution system of the Cooling Tower.

Table 10.4.5-3 describes the design parameters of the circulating water pumps.

Materials used in the CWS will resist long term corrosion.

In addition to circulating water, normal service water is provided from the cooling tower basin. The service water design requirement is approximately 47,235 gpm, bringing the total flow in the Cooling Tower to 538,007 gpm when adjusted to the average density of the combined flows. The Service Water System is detailed in Section 9.2.1.

Table 10.4.5-1 describes the design parameters of the Cooling Tower.

Loss of water inventory caused by natural evaporation, drift and blowdown requirements, is replaced by continuous makeup from the Main Reservoir by means of the cooling tower makeup pumps. One cooling tower makeup pump and one standby is provided. The two cooling tower makeup pumps are located in the Emergency Service Water and Cooling Tower Makeup Intake Structure. One of the two pumps is sufficient to supply the amount of makeup water required for the plant Circulating Water System. Table 10.4.5-2 describes the design parameters of the cooling tower makeup pumps.

Makeup water is pumped from the Emergency Service Water and Cooling Tower Makeup Water Intake Structure to the cooling tower basin. The makeup water flow is controlled by means of a level control valve in the makeup line that keeps the water level constant at the selected setpoint in the cooling tower basin. This level control valve also serves to control the cooling tower blowdown flow, by changing the water level setpoint in the cooling tower basin.

Debris from the makeup water is reduced by the traveling screens installed in the Emergency Service Water and Cooling Tower Makeup Water Intake Structure. In addition the self-cleaning strainers installed at the cooling tower makeup pump discharges, prevent debris larger than 1/16 inch from entering the system. The makeup water, as well as the cooling tower water, are considered clean. Removable screens are also provided for debris removal at the circulating pumps intake structure.

A chlorination system is provided for periodic chlorination of the CWS to control biological fouling of the condenser tubes and circulating water piping. Chlorination will not affect the materials used in the CWS. Provisions to supplement the chlorination system with a mechanical tube cleaning system are provided in the CWS piping.

Continuous blowdown from the cooling tower basin is required to maintain a controlled dissolved solid ratio. The normal blowdown rate is expected to be from 5200 to 9500 gpm. Blowdown is discharged to the Main Reservoir by the blowdown system. Makeup water requirements will vary throughout the year and will normally not exceed approximately 16,000 gpm. This value is based upon design ambient weather conditions when the evaporation and drift rate from the Cooling Tower is approximately 12,000 gpm.

10.4.5.3 Safety Evaluation

The Circulating Water System is not safety related. The CWS is normally used to supply cooling water to the main condenser to remove residual heat transferred from the Reactor Coolant System to the Main Steam Supply System during the initial cooling period of plant shutdown when the steam is bypassed to the condenser. However, if the CWS fails to supply cooling water due to failure of the circulating water pumps or the circulating water piping, the Atmospheric Steam Dump System will perform this function. This is considered a condenser failure and safe shutdown of the reactor in such an event is discussed in Sections 10.4.1 and 10.4.4.

An interlock is provided between the condenser steam dump valve and the condenser to assure that no steam is dumped to the condenser on loss of condenser vacuum signal as discussed in Section 10.4.1.5.

The CWS pump discharge valves are motor operated butterfly valves. Specific procedures, including system priming, for pump start up and shutdown to preclude the possibility of water hammer are observed.

Automatic control is provided for pump and motor protection during start up, operation and shutdown. This will assure proper pump bearing lubrication, motor bearing cooling and will prevent the pumps from operating continuously against a closed discharge valve.

Damage to safety related equipment due to the circulating water system leakage is prevented by plant arrangement and appropriate design features.

Flooding resulting from a postulated failure of the Circulating Water System at a completely failed circulating water expansion joint will not prevent safety related equipment from performing their intended design functions. Such flooding is limited to the Turbine Building, with resultant flooding of the condenser pit. Raised curbing at elevators and stairwells to condensate polishing areas are above the attainable level of the flood waters. Therefore, the minor flooding of the condensate polisher pit area, due to leakage through the concrete equipment hatches in the turbine building floor, is within the capacity of the Floor Drain System. See Sections 3.6.1 and 3.6.2 for further details regarding postulated piping failures.

There are three doors (D587, D602 and D603) between Reactor Auxiliary Building and Turbine Building at EL 240.00 ft (FSAR Figure 1.2.2-23). However, no water could enter this area because this area is isolated from the Cooling Water piping area of the Turbine Building by walls that are seismically designed to resist seismic forces and hydrostatic pressure due to flooding up to elevation 262 feet. All entrances to that area are curbed at EL 262.25 ft. Any water coming over the Turbine Building floor will drain out because the Turbine Building is open at EL 261.00 ft. This floor level is lower than curb level at EL 262.25 ft.

Flooding will have no detrimental effect on safety-related systems located within the Turbine Building. There are no passageways, pipe chases, or cableways from the Turbine Building to safety areas that are not flood protected so flooding of the Turbine Building will have no effect on operability of safety-related equipment.

A condenser circulating water expansion joint rupture results in the maximum flow rate (due to the circulating water pumps operating at runout) of approximately 700,000 gpm; however, this assumption is extremely conservative because if a failure does occur, it is more likely to develop gradually. The potential of a failure of a expansion joint is minimized by designing the joints to withstand pump shut off head and calculated water hammer.

Such a failure is detected by two level switches mounted in the condenser pit which will alarm in the Control Room upon large water accumulation. There is no automatic circuitry to isolate an expansion joint failure leakage.

In the case of a complete expansion joint failure, the plant operator will react to the high level alarm in the condenser pit and trip the three circulating water pumps. However, if the operator fails to react to this alarm, a second alarm indicating low water level in the cooling tower basin is provided to alert the operator to trip the three circulating water pumps. The minimum estimate of the time between the two alarms is eight minutes.

The Class 1E cable ducts, running beneath the Turbine Building between the Diesel Generator Building and Reactor Auxiliary Building, are sloped up toward the Diesel Generator Building. In the highly unlikely event that the flood water penetrates the Class 1E duct runs, after penetrating the turbine building floor, the water, seeking its own level, would not flood the Diesel Generator Building whose ground floor is at Elevation 261 ft. Flooding, if any, within the Reactor Auxiliary Building would be confined by curbing to the manhole where the duct enters the building.

The nearest edge of the Cooling Tower is located approximately 750 ft. from the Turbine Building and approximately 550 ft. from the closest Seismic Category I structure, the Diesel Generator Building. Collapse of the Cooling Tower is highly unlikely; however, should it occur, the tower would tend to collapse without distributing large pieces of debris over a large area outside the basin.

The lowest elevation of the cooling tower basin is shown at the extreme right of Section AA in FSAR Figure 10.4.5-2 and is EL 255.50 ft. The basin slopes downward to this point at the slope of 1/16 inch per foot. Water from the basin flows down into the cooling water intake structure. In the present configuration gravity drainage from this structure is not possible. Circulating water is drawn vertically by the circulating water pumps and is discharged into the circulating water piping above the roof of the intake structure. Any earthquake damage would tend to isolate this source of water from other plant areas.

Environmental influences of the Cooling Tower and its effects are discussed in Section 2.3.2.2.

Periodic injection of chlorine is provided for controlling slime, algae, and bacteriological growth within the Circulating Water System.

10.4.5.4 Test and Inspection

Preoperational and start up test are performed as described in Section 14.2.12 to verify proper operation and conformance with design. Tests and inspections will be conducted as necessary throughout the plant life to insure reliable system operation.

10.4.5.5 Instrumentation Application

Provisions have been made to control the circulating water pumps from the Control Room and a local control panel. Each circulating water pump is interlocked with its respective discharge valve so that a pump start signal initiates valve opening and a pump stop signal initiates valve closing. Status-indicating lights are provided in the Control Room for the circulating water pumps and their discharge valves.

Level indication is provided on the Cooling Tower Make-up Panel in the Control Room for the water in the cooling tower basin.

A temperature recorder is provided on the Cooling Tower Make-up Panel in the Control Room for the water inlet to the Cooling Tower.

Temperature instruments with inputs to the plant computer are furnished on the inlet and outlet circulating water line to the condenser waterboxes.

Alarms in the control room are provided to indicate the following abnormal conditions:

a) Loss of circulating pump motor bearing cooling water

b) Trip of any circulating pump that should be in operation

c) High and low water level in the cooling tower basin

d) High water level in the condenser pit

10.4.6 Condensate Polishing Demineralizer System

10.4.6.1 Design Bases

10.4.6.1.1 The Condensate Polishing Demineralizer System (CPDS)

(see Figures 10.4.6-1 through 10.4.6-3) is designed to:

a) Maintain the impurity levels within the limits required for all volatile treatment (AVT) of the feedwater.

b) Remove dissolved solids introduced into the condensate from circulating water in-leakage and steam generator blowdown when routed to the condenser.

The CPDS is not required for safe shutdown of the reactor and is designed as non-nuclear safety equipment.

10.4.6.2 System Description and Operation

The system consists of six mixed bed demineralizers; normally, five units are in operation when the system is placed in service and one unit is in standby. The system includes an external regeneration system, piping, valves, instrumentation and controls for proper operation and protection against malfunction. The system is controlled from a local panel and is operated in an automatic, semi-automatic, or manual mode. Valves and pumps are remotely operated from the local panel.

Since replacement of the steam generators and condenser tubes, the secondary water chemistry has been able to be maintained without having to place the CPDS in service for normal plant operation. The CPDS can be placed in service to assist with secondary water chemistry control when needed, such as during refueling outages or a condenser tube leak.

Instrumentation is provided on the effluent of the demineralizers to monitor performance. Visual alarms and annunciation are provided for the monitored parameters to indicate if the demineralizer unit requires regeneration.

The effluent is monitored when the CPDS is in service to assure that the effluent composition is within acceptable limits. A full flow bypass line will open if system differential pressure exceeds a preset limit. The bypass valve also opens on loss of power or air pressure.

Design specifics of the CPDS are summarized in Table 10.4.6-3. When instrumentation on an operating unit indicates approaching "breakthrough", the demineralizer in the off position is manually placed in rinse/recycle. Alarm points are set at anticipated levels to provide time for the spare demineralizer to be recycled and placed in service before the in service unit is completely exhausted.

On loss of power or operating air pressure, the demineralizer valves other than the bypass valve remain in the same position.

The regenerative waste is collected in a waste tank located in the Waste Processing Building and radiologically sampled prior to further processing. The waste is not expected to be radioactive and therefore, after sampling and neutralization is discharged to the cooling tower blowdown line. The waste can be neutralized directly in the waste tank or be sent to the waste neutralization system. In case of a primary to secondary leakage, the waste will become radioactive. In such a case the waste will be processed in the Liquid Waste Processing System (see Section 11.2).

Any chloride in the condensate would be due to leakage of the circulating water into the condenser and is removed by the CPDS. The unexhausted demineralizer is capable of keeping its effluent below the very low limits required for AVT chemical control. Laboratory and on-line analyses are made at regular intervals to verify that control limits are not exceeded.

The demineralizer system effluent is monitored by using process instruments and laboratory analysis.

10.4.6.3 Safety Evaluation

The CPDS does not constitute a potential radioactivity release path to the environment and has no safety related function. If the fluid being processed is radioactive due to leakage from primary to secondary, the system has the effect of concentrating the activity in the regeneration waste which is processed by the Waste Management System. Failure of any component could compromise the system operation, but would not affect any safety related equipment or prevent safe shutdown of the plant.

10.4.6.4 Test and Inspection

The CPDS is tested and inspected in accordance with Section VIII of the ASME, B&PV Code. In addition, shop and field adjustments and tests are conducted to verify proper operation of the system. Preoperational tests will be conducted as described in Section 14.2.12.

10.4.6.5 Instrumentation Application

Instrumentation includes conductivity measurement, sodium analyzers, dissolved oxygen analyzer, differential pressure indication, flow indication, and flow totalizers.

Effluent conductivity from each demineralizer and from the common system effluent header is monitored to provide indication of system exhaustion. High total and cation conductivity and sodium on a unit's effluent is visually indicated in the secondary sample room and is annunciated in the main control room and locally. The exhausted unit will be removed from service after the spare unit is placed in service.

Sodium analyzers alarm in the secondary sample room indicating high sodium levels.

On the effluent header, the following instruments are provided for monitoring:

a) Total and Cation Conductivity - With high conductivity alarm in the secondary sample room and main Control Room.

b) Sodium - With sodium concentration alarm in the secondary sample room and main Control Room.

c) Dissolved Oxygen - With high alarm in the secondary sample room and main Control Room.

Instrumentation includes suitable differential pressure monitors, pressure indicators, annunciators, recorders and alarms for each unit.

10.4.6.6 Analysis of Demineralizer Capacity

The demineralizer is designed to remove the influent ions present resulting from a 10 gpm circulating water leak into the condenser. Table 10.4.6-2 contains a list of impurities in the circulating water prior to leakage into the condenser. The demineralizer is designed for a pressure drop of 50 psig across the bed.

With a 10 gpm leak from the circulating water system into the condenser, the exhaustion time of a demineralizer is more than 100 hrs. Since the regeneration time is approximately 20 hrs., the possibility of not having a standby demineralizer when needed is unlikely.

10.4.7 Condensate and Feedwater Systems

The function of the Condensate and Feedwater Systems is to return water from the condenser to the steam generator. The Condensate and Feedwater Systems are shown schematically on Figures 10.1.0-3 and 10.1.0-4 and important design features are summarized in Tables 10.4.7-1, 10.4.7-2, 10.4.7-3, and 10.4.7-4.

10.4.7.1 Design Bases

The systems are designed to provide feedwater continuously to the steam generators, to maintain steam generator water levels within desired limits during plant normal steady state and transient operation, and to ensure uniform feedwater temperature to all steam generators under all operating conditions. During steady state operation, feedwater inventory will remain approximately constant. Transient conditions will have the following effect on the Condensate and Feedwater Systems (see Section 10.4.7.2 for a description of the operation of these systems under transient conditions):

a) Atmospheric steam release results in loss of fluid from the systems.

b) Condenser steam dump results in no loss of fluid from the systems.

c) Ten percent step load or five percent per minute ramp changes will be achieved without steam dump or major effect on Feedwater System. Fluid inventory transfer within the system is accommodated by the storage capacity of the system.

d) A step reduction in excess of ten percent in load will result in steam dump and loss of heater drain pump flow due to flashing. Condensate flow will increase as necessary to make up for the loss of heater drains.

The system provides for condensate deaeration in the condenser and the addition of amine (pH control) and hydrazine or equivalent (oxygen scavenging) as required in the condensate polisher effluent discharge piping, the number 5 feedwater heaters' outlets, the moisture separator reheater drain tank inlet or the moisture separator drain tank inlet header.

Each steam generator is provided with an auxiliary feedwater nozzle in addition to the main feedwater nozzle. During initial plant startup, either the main feedwater or the auxiliary feedwater system is used to introduce makeup water to the steam generator. Transfer from the auxiliary feedwater system to the main feedwater system is made any time prior to exceeding the point of adding heat.

All condensate and main feedwater system piping extending from the condenser, up to but not including the check valves upstream of the main feedwater isolation valves outside the Containment, is designed in accordance with the ANSI B31.1 Power Piping Code requirements. Those portions of the main feedwater system piping from and including the above check valves outside the Containment to the steam generator feedwater nozzles are Seismic Category I, and designed to ASME Section III, Class 2.

The Feedwater System and Condensate System piping has been designed to withstand possible fluid flow instabilities, i.e., water hammer during all plant operating conditions (see Section 3.9.2.1).

The Condensate and Feedwater Systems include provisions for automatic isolation of the Feedwater System from the steam generators upon receipt of a main feedwater isolation signal (MFIS) (see Section 7.3). These main feedwater isolation valves are categorized containment isolation valves and, as such, are located as close as practical to the containment wall (see Section 6.2.4).

The Condensate and Feedwater Systems are designed such that breaks in system components or piping will not result in adverse effects on the functional performance of essential systems or essential components.

The plant can be safely shutdown using the water from the Auxiliary Feedwater System as described in Section 10.4.9. Environmental conditions affecting the portions of the Condensate and Feedwater Systems located in the Containment and Reactor Auxiliary Building are discussed in Section 3.11.

10.4.7.2 System Description

The Condensate and Feedwater Systems are shown schematically in Figures 10.1.0-3 and 10.1.0-4. The Feedwater System piping arrangement in the Reactor Auxiliary Building and in the Containment are shown on Figures 10.4.7-1, 10.4.7-2, 10.4.7-3, and 10.4.7-4.

The condensate is pumped from the condenser hotwell by two 50 percent capacity direct motor driven condensate pumps through the gland steam condenser and the full flow condensate demineralizer to the suction of two 50 percent condensate booster pumps. A fixed orifice in the main condensate line provides the pressure drop needed for assuming proper gland steam condenser flow. The Condensate System also includes a bypass between the condensate demineralizer inlet and outlet headers. The bypass can be operated automatically or manually. In the automatic mode of control, it will prevent excessive differential pressure across the demineralizer resin beds or bypass the resin beds if an alarm condition is present. See Section 10.4.6 for a discussion of the condensate demineralizer.

The condensate booster pumps are driven by induction motors through variable speed fluid couplings. The condensate booster pumps discharge through two trains of four low pressure feedwater heating stages into two 50 percent capacity motor driven steam generator feedwater pumps.

Each of the two feedwater pumps discharge to the feedwater control complex through a header connected to two, 50 percent single stage high pressure feedwater heaters. The feedwater flow to the steam generators is controlled automatically by the main feedwater control valves over a load range of approximately 15 to 100 percent. Bypass control valves, which allow automatic control of feedwater flow over the range of approximately 0 to 15 percent, are provided in parallel with the main feedwater control valves.

Due to the load drop and subsequent loss of pressure in the heater drain pump suction piping, the heater drain pumps will trip. The condensate and the condensate booster pumps will make up for the loss of heater drain pump flow in order to meet the steam generator feedwater pump demand. The variable speed fluid coupling will increase the condensate booster pump speed to handle this transient. Flow requirements to meet steam generator feed pump demand can thus be met.

The condenser hotwell has a storage capacity equal to approximately five minutes of full load operation. This capacity is sufficient to allow condensate supply for the make-up of steam generator inventory during a full external electrical load drop due to steam dump to atmosphere and steam generation level decrease caused by the increase in steam generator steam pressure.

Condensate make up is supplied to the condenser hotwell from the condensate storage tank through a level control valve. Excess condensate is discharged to the condensate storage tank through a level control valve from either the discharge of the condensate pumps or the discharge of the condensate booster pumps.

Heater drain pumps, condensate booster pumps and main feedwater pumps are protected against flashing at the pump suction by means of electrical interlocks which trip the respective pumps on low suction pressure.

Each condensate and feedwater pump is equipped with an automatically controlled recirculation system to permit direct circulation back to the condenser for pump protection during low flow operation. Heater drain pump recirculation flow is returned to low pressure feedwater heaters Nos. 4A and 4B.

During normal operation, feedwater is supplied to the steam generator by way of 16 inch outside diameter main feedwater lines routed to the main feedwater nozzles located on the upper shell.

During start-up, feedwater can be supplied by the main feedwater system through the main feed nozzle or the auxiliary feedwater system nozzle (up to the point of adding heat) through the auxiliary feedwater nozzle.*

Steam generator level is maintained by a three element feedwater control logic which modulates the feedwater control valves based on steam generator level, steam flow, and feedwater flow.

During normal operation, the valve positioner is used to move the actuator piston which moves the stem in the desired direction. The pneumatic actuator system is fail safe in that the AOVs reposition on a loss of air to their fail safe position. The fail safe position vents air from the bottom of the piston and injects air from the air accumulator above the piston.

A feedwater isolation signal or an SI signal will de-energize the two redundant solenoids which will vent the air supply to the quick exhaust valve. This will cause the normal air supply to the actuator to isolate. Simultaneously, the air accumulator is aligned to the top of the actuator while the bottom of the actuator is vented. This results in the fail-safe closure of the FRV.

The feedwater flow control and flow control bypass valves will close within eight and ten seconds, respectively, in response to the following:

a) Signal to close from the reactor protection systems logic (two independent signals);

b) Loss of power signal from the reactor protection systems logic;

c) Loss of control air;

d) Loss of DC power to either solenoid valve.

No credit for non-nuclear safety class equipment is taken since failure of any of the controlling services (air, power, control signal) will cause the feedwater regulating and bypass valves to fail closed.

Chemicals are added to the feedwater for oxygen scavenging and pH control. Steam generator blowdown is used in conjunction with chemical addition to maintain steam generator water and feedwater quality.

The main feedwater flow control valves and bypass flow control valves in the main feedwater lines are located upstream of the respective containment isolation valves. These valves are non-safety related and installed in non-nuclear safety class piping; however, the valves themselves are procured to ASME Section III, Class 3, Seismic Category I requirements in order to assure their reliable closure assuming a single failure, in the event of a feedwater line break downstream of the containment isolation valves without loss of non-nuclear safety class feedwater piping or feedwater flow. In this event, failure of a Containment isolation valve in an open position would allow continued feedwater flow into the Containment. Consequently, the control valves add redundancy to prevent an unisolated feedwater flow into the Containment.

Clean-up of the Condensate System prior to plant operation can be performed by using a recirculation line upstream of the feedwater regulating valves which allows circulation of condensate through the feedwater pumps and No. 5 heaters back to the condenser hotwell. During operation, this line is isolated by a manual gate valve.

10.4.7.3 Safety Evaluation

Operation of the condensate and main feedwater pumps is not required for safe shutdown of the plant. The Auxiliary Feedwater System will supply feedwater for safe shutdown in the event of total loss of condensate and feedwater flow (refer to Section 10.4.9).

Samples of condensate and feedwater are drawn from condenser hotwells and condensate and feedwater piping for the purpose of analysis and control of secondary system water chemistry. The normal levels of amine and hydrazine in the feedwater are non-toxic.

During normal plant operation, the Condensate and Feedwater Systems are nonradioactive. In the event of a steam generator tube leak, it is possible for the condensate and feedwater to become radioactively contaminated. The steam generator blowdown and the condenser vacuum pump effluent have dedicated radiation monitors (see Section 11.5). The gland steam condenser and condenser vacuum pump effluent exhaust to the turbine building vent stack, which has a WRG monitor for detecting activity prior to release of effluents to the environs. Expected source terms for the secondary system are given in Section 11.1. The Condensate Polishing Demineralizer System and steam generator blowdown demineralizers will remove a large portion of any contamination. The effluent from the condenser vacuum pumps, the blowdown demineralizers, and the polisher regeneration waste, is treated as contaminated if necessary.

Each main feedwater isolation valve (MFIV) actuator is physically and electrically independent of the other such that failure of one will not cause failure of the other. The MFIV's are equipped with pneumatic actuators. Each valve has an accumulator with a stored source of nitrogen which is the motive force for operation. Upon loss of electric power the condensate, the condensate booster, and the feedwater pumps trip; also, backflow is prevented by check valves.

The design of the Condensate and Feedwater Systems is in accordance with the requirements of Section 3.6 to ensure adequate protection of essential components against the effects of postulated pipe rupture. The effects on the NSSS of component failure and accidental breaks in the condensate and feedwater piping are evaluated in Chapter 15.

Leakage from the Condensate and Feedwater Systems is detected by level instruments in the condenser hotwell. Condenser level is automatically maintained by makeup from or discharge of condensate to the condensate storage tank (see Section 9.2.6). Leakage from the Condensate and Feedwater System is collected by the turbine building drains, which have radiation monitors (see Section 11.5).

10.4.7.4 Tests and Inspections

The condensate, feedwater, and heater drain pumps are shop inspected and tested in accordance with the standards of the Hydraulic Institute. Pump pressure boundaries and other individual components of the system such as feedwater heaters, valves, etc., are hydrostatically tested at the vendor's plant in accordance with applicable codes. All tube to tubesheet joints of the feedwater heaters are hydrostatically tested at the vendor's shop for leaktightness. After installation and prior to operation, the entire Condensate and Feedwater System receives a field hydrostatic test and inspection in accordance with the applicable codes. ASME Section III, Code Class 2 main feedwater piping and valves are inspected and tested as described in Section 6.6 and Section 3.9.6. Pre-operational and start-up tests are conducted as described in Section 14.2.12.

10.4.7.5 Instrumentation Application

Control Room displays for the condensate pumps, condensate booster pumps, feedwater pumps, and heater drain pumps include indicators for pump discharge pressure, start/stop switch position, and recirculation valve position. Instrumentation and controls are provided for regulating pump recirculation flow rate for the condensate pumps, condensate booster pumps, heater drain pumps, and feedwater pumps.

Flow elements and transmitters located on the feedwater line to the steam generators provide a signal for the Main Feedwater Control System. The Main Feedwater Control System is described in Section 7.7.

The following is a list of the most essential parameters to be displayed and alarmed in the Control Room:

a) Feedwater flow rate

b) Steam pressure of each steam generator

c) Feedwater header pressures

d) Steam generator level

e) Status indication of all power-operated valves

f) Feedwater temperature

10.4.8 Steam Generator Blowdown System

The Steam Generator Blowdown System (SGBS), shown on Figure 10.1.0-6 is used in conjunction with the Secondary Sampling System to control the chemical composition of water in the secondary side of the steam generator shells within specified limits and to prevent the buildup of corrosion products. Steam Generator Blowdown System removes contaminants and corrosion product accumulations from the steam generators to maintain secondary water chemistry within prescribed limits.

10.4.8.1 Design Basis

The SGBS is designed to fulfill the following requirements:

1. To provide a continuous blowdown flow rate between 10,000 lb/hr minimum and 43,000 lb/hr maximum continuous (1% of maximum steaming rate, MSR) per steam generator during normal plant operations;

2. To permit a maximum blowdown flow rate of 86,000 lb/hr (2% of MSR) per steam generator for unusual events that adversely affect feedwater chemistry, such as when main condenser inleakage is above acceptable levels. Use at the 2% level is limited to 18 months over the 40 year life of the steam generator.

3. To achieve and maintain the chemistry requirements of the water inventory in the Condensate and Feedwater Systems during plant start-up and during full power operations. See Section 10.3.5 for water chemistry requirements.

The portion of the SGBS from the steam generators to and including the air-operated containment isolation valve and manual containment isolation valve comprises an extension of the steam generator boundary. This portion of the system has been designed in accordance with Safety Class 2 and Seismic Category I requirements. The piping from the isolation valves outside Containment up to the Reactor Auxiliary Building-Turbine Building interface wall is designed in accordance with Safety Class 3, Seismic Category I requirements. This portion of the piping has been upgraded to limit the extent of high energy pipe rupture considerations, see Sections 3.6.1 and 3.6.2. The remainder of the system is non-seismic and non-safety related (see Section 3.2).

The Steam Generator Blowdown System is shown schematically on Figure 10.1.0-6. The system is designed in accordance with Westinghouse recommendations regarding maximum permissible flows from the steam generator blowdown connections. The maximum flow criteria is imposed to prevent excessive erosion of the internal pipe to the blowdown connections over the design life of the steam generator.

The Steam Generator Blowdown System components have been designed in accordance with the American Society of Mechanical Engineers Code, Sections II, III, VIII - Div. 1 and the American National Standards Institute ANSI Standard B31.1.

In addition, the system is designed to Regulatory Guides 1.26, 1.29 and 1.48 (refer to Section 1.8 for conformance).

10.4.8.2 System Description and Operation

Steam generator blowdown fluid is removed from the steam generator shells at one tube sheet blowdown nozzle. This fluid is brought outside of the Containment through isolation control valves.

The blowdown fluid is discharged into a common flash tank maintained at a pressure of 150 psig. Flashed steam from the blowdown system which is measured by a venturi flow element is normally discharged to the shell side of low pressure feedwater heaters Nos. 3A and 3B. A constant water level in the flash tank is maintained by controlling the water discharge from the flash tank to the main condenser. The water leaving the flash tank is measured by a venturi flow element before entering the main condenser.

During normal operations, blowdown fluid leaving the flash tank is directed through a heat recovery and cleanup system. This heat recovery and cleanup system is designed to recover the heat from the effluent of the flash tank back into the condensate system. The heat exchanger effluent may be processed by filters and demineralizers as directed by chemistry analysis. The heat exchanger and/or the cleanup system may be fully or partially bypassed as directed by plant conditions.

The blowdown flow from each steam generator (from Nozzle 30 as shown on Figure 10.1.0 6) is maintained by a flow control valve in the blowdown header adjacent to the flash tank. Opening of this valve allows the blowdown from the steam generator to pass to the flash tank. Before commencing blowdown, the flow control valve in the blowdown header is closed, and the steam generator blowdown isolation valves are closed. Blowdown is initiated by opening the isolation valves and flow is controlled by modulating the flow control valve in the blowdown header. Flow through this flow control valve (and through Nozzle 30) to the flash tank increases until the pressure drop across Nozzle 30 is approximately 2 psid. This indicates the maximum blowdown flow has been reached and that the flow control valve should not be opened further to minimize the amount of flashing in the header and assure safe, efficient operation of the blowdown system.

A bypass line around the outside containment isolation valve contains a manual containment isolation valve and manual throttle valve to minimize the effects of water hammer during blowdown initiation. The bypass line is used to initiate blowdown following periods of system shutdown greater than 30 minutes. Blowdown flow is initiated by opening the flow control valve adjacent to the flash tank and the isolation valves inside containment. The bypass line isolation valve is opened followed by a slow opening of the throttle valve. Flow to the blowdown header downstream of the outside containment isolation valve is established to warm up the piping and to collapse voids in the piping. The flow control valve is closed, followed by closing the bypass line isolation valve and throttle valve after verifying blowdown header pressure downstream of the outside containment isolation valve is above the isolation valve automatic closure set point.

The steam generator blowdown rate is determined by the results of the steam generator shell water sample analyses, and by sodium content in the feedwater.

During normal plant operation, the steam generator requires very little blowdown. This small blowdown rate is required to maintain steam generator water chemistry. A radionuclide inventory of the secondary loop with an assumed primary-to-secondary leak and fuel cladding failure is provided in Section 11.1.

10.4.8.3 Instrumentation and Controls

Instrumentation and controls are provided to ensure proper valve operational sequencing of the SGBS system. A high-high level alarm is provided for the flash tank to alert the operator of overfilling. If the flash tank reaches high-high level, the steam generator blowdown control valves are automatically closed. Blowdown flow to the condenser is blocked in the event of high level in the condenser hotwell.

Three flow elements, installed in the following locations are used to monitor steam generator blowdown flow.

1. Steam generator blowdown flash tank steam outlet

2. Steam generator blowdown flash tank liquid outlet downstream of the condensate cooling mixing chamber

3. Condensate cooling water inlet line to steam generator blowdown mixing chamber

See Table 10.4.8-1 for a summary of the design data of the equipment.

10.4.8.4 Safety Evaluation

The SGBS constitutes a potential radioactivity release path to the environment even though two barriers exist between the fission products and the environment. Therefore, a means of monitoring and controlling the blowdown is an integral feature of the system design.

The portion of the SGBS from the steam generator to and including the containment isolation valves (located outside containment) comprises of an extension of the steam generator boundary. Therefore, an inside containment isolation valve is not required. These valves and piping constitute part of the containment boundary and are discussed in Section 6.2.4.

The blowdown and sample lines and valves inside the Containment are protected from missiles to avoid any interaction between a postulated LOCA and the blowdown and sample lines integrity.

The system isolation valves located in each blowdown line receive automatic actuation signals from separate channels to ensure that the single failure criterion is met. The isolation valves close automatically on an auxiliary feedwater actuation signal or a safety injection signal. See Section 7.3 for a description of the actuation signals.

A failure of any component in the system could compromise the system operation but would not affect safe shutdown of the plant.

Sampling of the steam generators is described in Section 9.3.2.2.1 to include grab sample capability at the process sample panel for radiological analysis in the Hot Lab. A radiation monitor is provided on the flash tank discharge line as described in Section 11.5.2.7.1.3 and as shown on Figure 10.1.0 6.

10.4.8.5 Tests and Inspections

The Containment Isolation System will be tested in accordance with the procedure outlined in Section 14.2 and the Technical Specifications.

The safety-related portions of this system will be inspected in accordance with Section 6.6.

The remainder of the SGBS will also be tested to ensure satisfactory operation.

10.4.9 Auxiliary Feedwater System*

The Auxiliary Feedwater System serves as a backup system for supplying feedwater to the secondary side of the steam generators at times when the normal feedwater system is not available, thereby maintaining the heat sink capabilities of the steam generator. The system provides an alternate to the Feedwater System during start-up, hot standby, and cooldown and also functions as an engineered safeguards system. In the latter function, the Auxiliary Feedwater System is directly relied upon to prevent core damage in the event of transients such as loss of normal feedwater or a secondary system pipe rupture.

10.4.9.1 Design Bases

The Auxiliary Feedwater System (AFS) is designed to supply sufficient quantities of feedwater to the secondary side of the steam generators to achieve stable hot standby conditions and plant cooldown if necessary.

Plant conditions which may be accompanied by the unavailability or a loss of normal feedwater and therefore require operation of the AFS are:

1. Loss of main feedwater with offsite power available
2. Loss of main feedwater without offsite power available
3. Feedline rupture
4. Steamline rupture
5. Loss of all AC power
6. Loss of coolant accident (LOCA)
7. Steam Generator Tube Rupture

The causes and analyses of the above events are discussed in Chapter 15. The flow requirements for the Auxiliary Feedwater System were established based on these analyses, as well as upon the cooldown operations following these events. The auxiliary feedwater flow rate required to provide adequate protection for the core and to assure an emergency cooldown has been established by Westinghouse. The auxiliary feed pumps are capable of supplying to the steam generators 475 gpm each from the two motor driven pumps and 900 gpm from the

* Further information contained in TMI appendix.

turbine driven pump. The two motor-driven auxiliary feedwater pumps have a design capacity of 450 gpm but can provide more than 475 gpm with their recirculation lines closed.

Thus for Condition IV events, the AFS has the capability of supplying 200 percent of the required flow even with a failure of the largest pump.

For a transient or accident condition, the minimum flow is delivered to at least two effective steam generators within approximately one minute of the automatic auxiliary feedwater actuation signal. After any transient or accident, the system is capable of maintaining the required flow for a period of time (at least two hours) sufficient to attain stable zero load hot standby conditions.

In addition, the Auxiliary Feedwater System provides sufficient flow (374 gpm minimum) to cool the plant from zero load hot standby conditions down to a reactor coolant hot leg temperature of 350F, where the Residual Heat Removal System is operated. The 350F RHR initiation temperature corresponds to a steam generator pressure of 125 psia with a reactor coolant pump operating or 100 psia if only natural circulation exists in the Reactor Coolant System.

Although the Auxiliary Feedwater System functions as an emergency system, it also serves as an alternate feedwater system during hot standby and cooldown operations whenever conditions are such that shutting down the Feedwater System is advantageous. The Auxiliary Feedwater System may also be used to adjust steam generator water levels prior to and during plant start-up and to establish and maintain wet layup conditions in the steam generators.

During hot standby, the Auxiliary Feedwater System operation time depends on the reactor power history. After an extended power run, if the Auxiliary Feedwater System is used to feed the Steam Generators, it would operate continuously for the first several hours after shutdown and periodically thereafter, depending on the heat input.

The motor driven AFW pumps are designed to operate for up to 300 hours continuously on recirculation. This allows the operators to leave one pump running for an extended period of time and to feed the steam generators as needed without exceeding the starting duties of the pump motors.

Components and piping of the AFS from and including the containment isolation valves to the steam generator nozzle are designed and fabricated in accordance with the requirements of ASME III, Class 2. Other AFS components and piping are designed and fabricated in accordance with ASME III, Class 3 requirements. Section 10.4.9.3 contains additional information on safety-related design bases.

10.4.9.2 System Description

10.4.9.2.1 General information

The Auxiliary Feedwater System flow diagram is shown on Figure 10.1.0-3, and 10.1.0-4 and the performance characteristics of its principal components are summarized in Table 10.4.9-1.

The Auxiliary Feedwater System (AFS) consists of two motor driven pumps and one turbine driven pump with associated valves, piping, controls, and instrumentation. The system components are located in the Reactor Auxiliary Building in the engineered safety feature systems area with the exception of the Condensate Storage Tank (CST), which is located in the Tank Building, and the supply piping to the steam generator which is located in the Containment Building.

Water hammer in the Auxiliary Feedwater System (AFS) is minimized by designing the system to remain full of water. The suction piping to the AFW pumps and part of the discharge piping are always maintained under a positive head of water due to the higher elevation of the CST. The discharge piping from the steam generator nozzle to the first check valve is pressurized to steam generator pressure. CST static head pressure and leakage across pumps and valving will maintain a water solid system on the AFW pump discharge side. Vents are provided at appropriate high points. Vent lines are opened prior to system start-up, where the system may have been drained, to vent any trapped air.

10.4.9.2.2 Flow path

The motor driven and turbine driven auxiliary feedwater pumps normally take suction from the Condensate Storage Tank (CST) via a common supply line. The CST is sized to maintain a minimum inventory for AFW plus sufficient margin for normal condensate system makeup and surges. The design basis for sizing the condensate storage tank is described in Section 9.2.6. Tank makeup water is supplied from the demineralized water storage tank through the demineralized water transfer pumps.

The alternative to the CST when it is depleted is the Emergency Service Water System. Switchover to this system is performed manually from the main control board or the auxiliary control board. Operating procedures for the AFW will identify the point at which switchover to the ESW should occur. Instrumentation available to monitor CST level are identified in FSAR Section 10.4.9.5.

The auxiliary feedwater pumps can also be remote manually aligned to take suction from the Emergency Service Water System, in the event of a loss of the CST. (See Sections 9.2.1, 9.2.5, and 9.2.6.) There are two isolation valves for each connection between the AFS and service water. This prevents inadvertent leakage contamination of the auxiliary feedwater by impurities in the service water.

The motor driven pumps discharge into a common header which supplies three independent lines, one for each steam generator. Each of these supply lines contain check valves, motor operated isolation valves, and flow control valves, and recirculation (bypass) valves as described below. The turbine driven pump supplies three additional lines, one for each steam generator. Each of these supply lines also contains check valves, motor operated isolation valves, and flow control valves. This arrangement thus provides two 100 percent capacity redundant motor driven AFW pumps and one 200 percent capacity steam driven AFW pump. Any single failure in the Auxiliary Feedwater System will not affect the capability of the system to provide sufficient cooling water to the Steam Generators.

The motor driven supply and the turbine driven supply for each steam generator are connected together, and a common line with flow element carries the water through the steam and feedwater pipe tunnel into Containment and connects to the auxiliary feedwater nozzle on the steam generator. Blockage of one of these common supply lines will not affect flow in the lines to the other two steam generators since these lines are independent.

10.4.9.2.3 Component description

The motor driven auxiliary feedwater pumps are powered from their respective emergency busses A and B. In the event of loss of the normal power source, power is supplied by the emergency diesel generators associated with these power busses. A recirculation (bypass) line is provided on the motor driven AFW pump discharge line to allow recirculation back to the Condensate Storage Tank (CST). The recirculation (bypass) valves (3AF-V187SA-1 and 3AF-V188SB-1) are normally open.

The motor driven auxiliary feedwater pumps are protected against excessive runout at low steam generator pressure by an electro-hydraulically operated pressure control valve in the discharge line from each pump. These valves maintain pump discharge pressure above a pre-set minimum value.

The steam turbine driven auxiliary feedwater pump is powered by a single stage, solid wheel, non-condensing, horizontal split casing steam turbine which discharges to the atmosphere. It is designed for start-up from a cold condition, and will operate with steam generator pressures ranging from 1200 psig to 105 psig. The TDAFW pump governor utilizes a digital speed controller and digital positioner to control turbine speed.

Steam for the auxiliary feedwater pump turbine is supplied from two steam generators and taken from the main steam lines upstream of the main steam isolation valves. The turbine steam supply valves are DC motor operated valves powered from the redundant vital DC busses. A check valve located downstream of each steam supply valve will prevent loss of steam to the turbine drive in the event of a steam line break.

The steam supply valves are normally closed and will receive a signal to open at the same time the steam turbine auxiliary feedwater pump actuation signal is initiated. The turbine trip and throttle (T and T) valve is normally open. A solenoid trip and a mechanical overspeed trip device are provided that will allow a spring to close the turbine stop valve. The solenoid trip is activated by local manual pushbutton, electrical overspeed, or Lo-Lo pump suction. An alarm is provided on the Main Control Board and on the Auxiliary Control Panel to alert the operator on Auxiliary Feedwater Pump overspeed or T and T valve shut. The power supply for the trip solenoid is 125V DC, thereby maintaining only DC powered control for the steam driven pump. To allow remote opening of the turbine T and T valve, a DC motor operator is provided. The auxiliary feed pump turbine is equipped with an electronic speed controller powered from a safety grade DC supply. This controller adjusts pump speed and therefore discharge pressure by opening or closing the turbine governor valve.

Each steam generator auxiliary feedwater supply line from the motor driven auxiliary feedwater pump discharge header contains a Safety Class 2 motor operated auxiliary feedwater isolation valve in series with a Safety Class 3 electro-hydraulic operated flow control valve. Each valve on each steam generator auxiliary feedwater supply line is powered from redundant vital AC power trains. Each turbine driven pump steam generator supply line contains a Safety Class 2 normally open DC powered motor operated auxiliary feedwater isolation valve in series with a Safety Class 3 electro-hydraulic AC operated flow control valve powered from the uninterruptable AC instrument panels. Thus, loss of all AC power will not affect the capability of the turbine driven pump to supply water to the steam generators for at least two (2) hours.

10.4.9.2.4 System operations

The AFS may operate during cooldown, hot standby, start up, and testing. It is lined up for automatic starting on any of the following signals:

a) Motor driven pumps:

    1) Safety injection

    2) Lo-Lo level in one steam generator

    3) Loss of both main feedwater pumps

    4) Loss of off-site power

    5) AMSAC

b) Turbine driven pump:

    1) Lo-Lo level in two steam generators

    2) Loss of off-site power

    3) AMSAC

The AFS can also be started or shutdown remote manually from the Main Control Board (MCB) and from the Auxiliary Control Panel (ACP).

The flow rate to each steam generator may be controlled remote manually from the MCB or ACP by modulating the appropriate flow control valves in the turbine and motor driven supply lines.

10.4.9.3 Safety Evaluation

The AFS is capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, and floods (see Chapter 3). In addition, all components of the AFS except the CST, are located within the Reactor Auxiliary Building and the Containment Building which provide protection against the effects of externally generated missiles. The CST is classified Safety Class 3, Seismic Category I. A concrete enclosure protects the tank from tornado, hurricane, and missile damage. Components of the AFS located within the Reactor Auxiliary Building and Containment Building are protected against the effects of internally generated missiles by separation and enclosures (see Section 3.5.1). All components of the AFS are protected against the dynamic effects associated with high and moderate energy piping failures as described in Sections 3.6.1 and 3.6.2. The AFS has been designed to operate in the environment resulting during normal and accident plant conditions as described in Section 3.11.

The AFS design ensures that there is no initiating failure and assumed single failure that will render all three AFW pumps and associated systems as unavailable in providing the necessary coolant flow to the appropriate steam generator(s).

The turbine driven AFW pump steam supply line downstream of the normally closed steam supply valves is classified as a moderate energy line under the 2% rule described in SRP 3.6.2, BTP MEB 3-1. The motor driven AFW pumps and its associated systems will be the system used for AFW during startup, hot standby or shutdown. The turbine driven pump and its associated piping up to the normally closed supply valves are not used during normal operation, startup, hot standby or normal shutdown. Also, the steam supply piping to the AFW pump turbine is sloped toward the turbine in order to avoid collection of condensate and thereby prevent damage to the piping system due to water slugging effects.

The Auxiliary Feedwater System is capable of performing its intended safety function despite the single failure of any component. See Table 10.4.9-2 for a summary of the failure mode and effects analysis for the AFS.

The system is designed with adequate provisions to manually initiate the protective actions of the system from the auxiliary control panel in the event the Control Room must be evacuated.

During normal power operation, pipe rupture in the main feedwater, high pressure portion of auxiliary feedwater (the high pressure portion of the AFS during normal power operation starts with the check valve in the steam generator subcompartment and goes to the steam generator nozzle), or Main Steam Supply System would be the most severe piping failure with respect to AFS performance requirements. These failures would result in a turbine and reactor trip; therefore, off-site power is assumed unavailable in accordance with Branch Technical Position APCSB 3-1. Even with an assumed single active failure, the AFS would have more than adequate capacity to supply the required flow.

The postulation of a normally locked-open administratively controlled manual valve to fail and block flow to the AFW is not considered a credible event. However, if the supply of the CST to the AFW pumps is blocked, pressure switches are provided for the AFW pumps (motor, turbine driven) suction side to provide Lo pressure alarm and a pump trip at a Lo-Lo pressure valve. As shown in Figures 7.3.1-9 and 7.3.1-10, alarm indication is provided for operator action. The supply line is normally water solid and will provide static head to the pump suction. Loss of the CST water supply to the AFW pumps due to blocked flow in the supply line (valve jams closed) will cause low pump suction pressure and the pump will trip prior to air being drawn into the AFW pump supply header. Switchover to ESW will provide water to the pump supply header and keep the supply water solid.

In the event of a steam line or main feedwater pipe break, the system will automatically isolate auxiliary feedwater flow to the affected steam generator and is designed to assure that the minimum required flow rate is directed to the unaffected steam generators. Each supply line from the AFS motor driven pump discharge header is provided with a normally open, motor operated, AC powered, isolation valve connected to the B-train ESF bus. In addition, an AC powered electro-hydraulic operated flow control valve connected to the A-train ESF bus is provided in series with the isolation valve. This arrangement provides adequate redundancy for isolation of a faulted SG in the event of a single active failure of either valve.

Similarly, each discharge line from the steam driven AFW pump header is provided with a normally open, electro-hydraulic operated flow control valve powered through inverters by the B-train DC battery system. A normally open motor operated isolation valve is provided in series with the flow control valve and is powered through the A-train DC battery system. The steam supply header to the steam driven Auxiliary Feedwater Pump is provided with redundant lines each containing a motor operated isolation valve. Each valve is powered through its respective safety train DC battery system. Thus, sufficient redundancy and power supply diversity is afforded in order to assure isolation of a faulted steam generator.

Physical and electrical separation are maintained throughout the pump control, control signals, electrical power supplies, steam supplies and instrumentation essential for operation of each auxiliary feedwater pump. The motor driven AFS pumps are powered from the ESF electrical AC power distribution system, (Section 8.3.1). The controls associated with the turbine driven AFS pump are powered by the safety related 125 volt DC bus. The DC bus receives power from both its own batteries and battery charger associated with the corresponding ESF electrical AC distribution division. See Section 8.3.2 for a description of the design basis for the on-site DC power system.

Water hammer in the AFS is minimized by designing the system to remain full of water. The suction piping to the AFW pumps and part of the discharge piping are always under a positive head of water due to the higher elevation of the CST. The discharge piping from the steam generator nozzle to the first check valve is pressurized to steam generator pressure. CST static head pressure and leakage across pumps and valving will maintain a water solid system on the AFS pump discharge side. Surface mounted temperature elements are provided on the AFS piping to detect any steam back leakage. The detection and annunciation of steam back leakage will minimize the potential for bubble collapse water hammer. In addition, the AFS will be monitored for water hammer during the initial test program as described in Section 3.9.2.1.

The main steam supply piping to the AFW pump turbine is sloped in order to avoid collection of condensate and thereby prevent damage to the piping system due to water slugging effects.

A detailed review of the AFW system design addressing the TMI Action Plan (NUREG-0737) Item II.E.1.1 is presented in Table 10.4.9 3. Section I of Table 10.4.9-3 delineates AFW system compliance with the Standard Review Plan Section 10.4.9 Revision 2 while Section II of the table delineates AFW system compliance with Branch Technical Position ASB 10 1 Revision 2.

10.4.9.4 Inspection and Testing Requirements

The Auxiliary Feedwater System will undergo preoperational and start-up tests as described in Section 14.2.12. It will be verified that the system is not susceptible to hydraulic instabilities as part of the dynamic effects testing described in Section 3.9.2.1. Periodic tests as required by the Technical Specifications will be performed. In-service inspection will be carried out in accordance with Section 6.6, and the pump and valve testing requirements of Section 3.9.6 will apply.

The surveillance procedures for all operational surveillance tests will specify the valve lineups to restore the system to operation or standby status, as appropriate. The valve lineup will require independent verification of the lineup. This practice is also followed to restore the system to service after maintenance.

10.4.9.5 Instrumentation Requirements

The following parameters will be displayed on the Main Control Board and/or on the Auxiliary Control Panel to provide the operator with sufficient information to monitor and operate the system. Refer to Table 7.4.1-1, Monitoring Instruments for Safe Shutdown, for details.

1. Condensate storage tank level

2. Motor driven auxiliary feedwater pump discharge pressure

3. Turbine driven auxiliary feedwater pump discharge pressure

4. Auxiliary feedwater flow to each steam generator

5. Auxiliary feedwater pump status

6. Auxiliary feedwater pump turbine speed and steam inlet pressure

7. Auxiliary feedwater regulating valve position

8. Auxiliary feedwater isolation valve position

9. DC motor operated steam isolation valve position

10. Service water supply to AFS valve position.

The AFW pumps have an alarm for low pump suction, and a pump trip on low-low pump suction. Also included are low pump discharge pressure alarms.

Two (2) redundant safety grade level transmitters (LT-1CE-9010A-SA, LT-1CE-9010B-SB) are provided on the CST for tank inventory monitoring. There are two separate tank taps and tubing for transmitter monitoring. Both level transmitters provide a signal via train A and train B to separate safety grade level indicators. The redundant level indicators provide indication to operators at the MCB and ACP of CST water inventory. Also each level transmitter provides a signal to redundant CPU's. Each CPU, on a separate train has alarm and indication of tank water inventory.

Also, the level transmitter for train B provides a signal to six (6) level switches which in turn provide the following control functions:

1. One High Level - Controls tank make-up, no alarm.

2. One Low Level - Controls tank make-up, no alarm.

3. One High-High - Tank overflow, alarm.

4. One Low-Min - Indicates minimum level to meet tech. spec. quantity of water to meet accident requirements, alarm.

5. One Low-Low - Indicates approach to minimum water level for accident, alarm.

6. One Empty - Indicates approach to water depletion, and allows operator twenty (20) minutes to switch to alternate water supply, alarm.

The level switches provide four (4) alarms and indication on the MCB and ACP. System will fail in the alarm mode.

A detailed discussion of ESF instrumentation and controls is given in Section 7.3.

REFERENCES: SECTION 10.4

10.4.9-1 NLS-87-232 letter from R. A. Watson, CP&L, to Dr. J. N. Grace, NRC, dated October 29, 1987, "10CFR21 Notification Follow Up Report"

APPENDIX 10.4.9A AUXILIARY FEEDWATER SYSTEM AVAILABILITY ANALYSIS

10.4.9A AUXILIARY FEEDWATER SYSTEM AVAILABILITY ANALYSIS

10.4.9A.1 Introduction

The NRC has required that those plants with Westinghouse and Combustion Engineering designed nuclear steam supply systems that are under Operating Licensing review evaluate their Auxiliary Feedwater System availability in Reference 10.4.9A-1.

This report summarizes the results of an availability study of the SHNPP Auxiliary Feedwater System (AFS) generated in response to the NRC requirement (NUREG-1038, Safety Evaluation Report, Open Item No. 14). This availability study has not been updated to reflect subsequent changes to the AFS design. Accordingly, the information presented in this chapter is considered an historical record of CP&L's compliance with the NRC requirement and may not reflect the latest AFS design. Though the availability analysis is not revised following a design change, the impact of the change on AFS availability is fully evaluated via the 10CFR50.59 Review process to ensure the conclusions of the original analysis remain valid.

The primary purpose of this study is to assess the system availability to function on demand and to identify any areas where minor changes in design, operating procedures and/or system testing/maintenance practice could result in significant availability improvements. In accordance with the requirements of Reference 10.4.9A-1, the following three cases were analyzed:

1. Case 1 -Loss of Main Feedwater (LMFW).

2. Case 2 -Loss of Main Feedwater with Loss of Offsite AC Power (LMFW/LOOP).

3. Case 3 -Loss of Main Feedwater and Loss of Offsite and Onsite AC Power (Station Blackout) (LMFW/SB).

The technique used for the study is Fault Tree Analysis and the postulated top event is the failure of AFS to provide the required total flow to at least two of the three steam generators.

The steps in this study were:

1. System Definition - The objectives of the study and its scope and limitations were clearly defined.

2. System Model Construction - A Failure Modes and Effects Analysis for each component and common analysis were performed and the results were used to construct a system fault tree.

3. System Model Qualitative Analysis - The system model was examined to determine the combination of events (minimal cut sets) which can lead to system unavailability on demand.

4. System Model Quantitative Analysis - Probabilities of occurrence were determined for the basic events in the fault tree. These values were used to calculate the overall system availability and to weigh the relative importance of the events and event combinations as failure contributors.

5. Discussion of Results - The results of the qualitative analysis were reviewed to determine if any changes in design, operating procedures and/or system testing/maintenance practice could result in significant availability improvements.

6. Conclusions - Overall conclusions from the study were discussed.

10.4.9A.2 System Definition

10.4.9A.2.1 Top event

The purpose of the analysis is to determine the availability of the AFS to perform its design function on a demand produced by Loss of Main Feedwater (LMFW), LMFW with Loss of Offsite AC Power (LMFW/LOOP), and LMFW with Loss of All AC Power (Station Blackout) (LMFW/SB). Operation under main steam or feedwater line break or LOCA or SGTR conditions were not considered.

The total flow rate required for at least two of three steam generators to provide adequate protection for the core have been established by Westinghouse and are as follows:

1. 430 gpm for LMFW*

2. 400 gpm for LMFW/LOOP*

3. 380 gpm for LMFW/SB*

The postulated top events are the failure of AFS to provide sufficient flow to at least two of the three steam generators (SG's) or less than 430, 400, 380 gpm total AFS flow to less than two SG's for LMFW, LMFW/LOOP, or LMFW/SB, respectively.*

Since the basic failure events which were considered have small probabilities, the system model was constructed in fault tree fashion as opposed to success tree fashion. This was done to minimize roundoff error in the calculations.

Consistent with the NRC request in Reference 10.4.9A 1, the scope of the top event spans only the availability of the system to start on demand for the three transients under consideration and does not include the reliability of the system to carry out this mission through the required duration (several hours).

* Refer to Table 15.0.3-4 for the latest analysis assumptions on AFW flowrates.

10.4.9A.2.2 System boundaries

The AFS simplified flow diagram provided in the analysis, shows the system that consists of the AFS flow path from the Condensate Storage Tank (CST) to the Steam Generators, and the steam driven pump steam supply lines from the connection to the main steam lines to the pump turbines. Support system/ components considered in the analysis which are not shown on the figure are pump and valve control circuits, power supplies and actuating logic. More detail on the types of failure considered is given in the next section.

10.4.9A.2.3 Basic events and causes

The types of events considered in the Failure Modes and Effects Analysis (FMEA) and their possible causes are listed by component. It should be noted that in some cases, events which obviously were not failure events were not fully developed in the FMEA. Also, not all the possible causes listed under each component type are applicable to each event for the component.

<u>Manual Valve</u>

a) Events:

1. Open (able to pass flow).
2. Closed (unable to pass flow).

b) Possible Causes:

1. Plugging (flow path blocked).
2. In wrong position due to test or maintenance on another component at the time of demand.
3. Human error (failed to return to correct position following test or maintenance operation).
4. Normal or proper position.

<u>Check Valve</u>

a) Events:

1. Open against forward current.
2. Open against reverse current.
3. Closed against forward current.
4. Closed against reverse current.

b) Possible Causes:

1. Stuck in wrong position due to mechanical binding.

2. In test or maintenance.

3. Proper position.

Power Operated Valve

(Includes flow control valves, pressure control valves, turbine steam supply isolation valves, turbine governor valves, turbine trip and throttle valves.)

a) Events:

1. Remains open on demand close signal.

2. Remains closed on demand open signal.

3. Closed and receives no automatic signal.

4. Open and receives no automatic signal.

b) Possible Causes:

1. Mechanical binding.

2. Control circuit failure.

3. Actuating signal failure.

4. Motive force failure.

5. Left in wrong position (only if valve does not receive automatic actuation signal) after test or maintenance action (human error).

6. In wrong position due to test (only if valve does not receive a test override signal).

7. In maintenance.

Pump

a) Events:

1. Fails to deliver the required flow.

b) Possible Causes:

1. Pump mechanical failure.

2. Control circuit.

3. Actuating signal failure.

4. In maintenance.

5. Human error.

Actuating Logic

(Includes the various Engineered Safety Features Actuation Signals used in the AFS.)

a) Events:

1. Signal not generated when required.

b) Possible Causes:

1. Unspecified electronic failures.

2. In test or maintenance.

AC Power Supply (DG's)

a) Events:

1. Does not supply power.

b) Possible Causes:

1. Diesel mechanical failure.

2. Generator mechanical or electrical failure.

3. DG in maintenance.

DC Power Supply (Battery)

a) Events:

1. Does not supply power.

b) Possible Causes:

1. Equipment failure.

2. In maintenance.

Passive fluid boundary failures or valve disc-steam separations were not considered.

Common cause failures considered as basic events are discussed in Section 10.4.9A.3.2. Common cause failures not considered were sabotage or those of a physical layout nature, such as non-seismic systems falling on AFS components, high energy line breaks in other systems affecting the AFS, etc. This is not to say that such possibilities do not exist in the plant design, it was simply not within the scope of this study to investigate them. These events are addressed in other areas of the FSAR.

10.4.9A.3 System Model Construction

10.4.9A.3.1 FMEA (Independent Failure Considerations)

FMEA is an inductive analysis that systematically details, on a component by component basis, all possible failure modes and identifies their resulting effects on the system. Possible single modes of failure or malfunction of each component in a system were identified and analyzed to determine the effect on surrounding components and system. The FMEA describes the effect that every component action has on the system, regardless of whether or not the action contributes to system failure, and is a necessary complement to the fault tree for this reason.

The structure and rationale behind the details of the FMEA is discussed below. The FMEA is given in Table 10.4.9A-2.

10.4.9A.3.1.1 Component

Each component selected in accordance with the criteria of Sections 10.4.9A.2.2 and 10.4.9A.2.3 appears in the FMEA, with the exception of vent and drain valves. These were not included because the system is kept continually full of water, so it is not considered credible that a vent or drain valve could be left open without being quickly noticed and corrected. A list of all components considered, along with a description of the component, is given in Table 10.4.9A-1 including revisions through Amendment 38 of the FSAR.

10.4.9A.3.1.2 Component State

Each component was considered in its extreme states within the limitations of Section 10.4.9A.2.3 for the purpose of analyzing its effects on the AFS. For example, valves were considered in both the open and closed state.

10.4.9A.3.1.3 Effects

Subsequent to the initial analysis, the AFW system was modified to include additional check valves in the discharge header to each steam generator. The addition of these components was found to have no measurable impact on the results of the reliability analysis.

Components were analyzed to determine the effect of each of their possible states on the system functionability. The following guidelines were used in analyzing the effect of the component states:

a) Valves - can impair system operation in the closed position by blocking flow where flow is desired, or in the open position by diverting flow or permitting flow where not desirable.

b) Pumps - can impair system operation by not pumping fluid as required.

c) Pump/Valve Control Circuits - failure can cause a pump not to start or valve not to change position when required, leading to the same system impairments discussed under a) and b) above.

d) Actuating Logic - can fail to issue a command to the pump or valve control circuits, leading to the same system impairments discussed above.

e) Power Supplies - can fail to provide electric power to pumps or valves, leading to the same system impairments discussed above.

10.4.9A.3.1.4 Inherent Compensation

The FMEA includes any inherent system design features which compensate for the failed state of the system components.

10.4.9A.3.2 Common Cause Failure Consideration

Several events were assessed for their potential to induce common cause failures in the AFS. These are discussed below.

a) Loss of Component Cooling Water - The AFS does not rely on Component Cooling Water (CCW). The AFS pumps, unlike the ECCS pumps, handle a relatively cool fluid which is sufficiently cool itself for pump cooling, so no CCW is required.

b) Loss of AC Power - The AFS Turbine Driven Pump (TDP) and all active valves associated with its flow and steam supply paths are independent of ac power. No TDP auxiliary functions, including lubrication, are dependent upon ac power. However, extended operation of the TDP is indirectly reliant on ac power since the ventilation system including unit coolers serving the pump cubicle is ac powered. Without ventilation for several hours when the pump is running, temperature in the pump area could become high enough to affect the pump controls, possibly in an adverse manner. This would not be an immediate failure, however, and time would be available to restore some power. As such, this failure mechanism was not factored into the fault tree.

c) Poor Water Quality Control - If very low quality water was used for extended periods in the AFS, it could conceivably cause corrosion/particle deposition in the system, resulting perhaps in binding the moving parts of the pumps and valves. However, it is not credible that this would occur to any extent in the AFS for the following reasons:

   1) Only condensate or demineralized quality water is used in the AFS except backup Emergency Service Water System (ESWS).

   2) The system is periodically flow tested, which not only provides some system flushing, but assures that water quality has not affected the pumps.

   3) The valves are periodically stroke tested, which would detect any loss of function due to corrosion or particle deposition.

10.4.9A.3.3 Fault Tree

The fault trees were constructed from the FMEA (independent failure analysis) and the common cause failure analysis. The failures and combinations of failures that could defeat operation of the subsystem (including failures from other subsystems) were combined using conventional AND and OR gates. Then the subsystems were arranged through a logic which related them to the "top event" specified in Section 10.4.9A.2.1. This step was particularly complex for the AFS due to its extensive interconnection of redundant trains and the multiple ways in which it can successfully perform its function.

To simplify the fault tree, only the failure contributing component states (or events) from the FMEA, and not all possible causes of the state were incorporated into the fault tree. For example, if a valve being closed (unable to pass fluid) was a contributor in the fault tree, "VALVE XX CLOSED" was included as the event in the fault tree rather than placing an OR gate in the tree with event inputs such as "VALVE XX CLOSED DUE TO MAINT", "VALVE XX CLOSED DUE TO ERROR", "VALVE XX PLUGGED WITH DEBRIS", etc. The latter would generate an unmanageable number of cut sets, and would produce a computer analysis output which focused on causes of concern as opposed to component of concern, which is more useful. The causes and probabilities of each event along with the rationale for their selection is listed in Section 10.4.9A.5.1.

A single fault tree including all components considered in the study was first generated and this fault tree represented the system under Case 2. The Case 1 fault tree was then developed by applying the SETS FRMNEWFT procedure to the Case 2 fault tree with the PHI option to delete AC power failures (since offsite power is given to be present for this case) and by manually adding as a system failure the inability of the MDP recirculation lines to isolate when the only AFS pump available is a single MDP. The Case 3 fault tree was also developed by applying the FRMNEWFT procedure to the Case 2 fault tree, but using the OMEGA option to assure AC power failure.

It was assumed that the operator did not correct component failures, except the following:

a) The operator is assumed to be available to back up the automatic actuation of the AFS system. This is considered reasonable because the operating guidelines for plant transients call for the operator to confirm auxiliary feedwater actuation immediately after confirming reactor trip, and to take action to restore auxiliary feedwater if it is not functioning. Both system and component level controls are available to the operator in the Main Control Room. Failure of the operator to back up system automatic level actuation signals has been factored into the fault tree as event HE1.

b) The operator is assumed to be available to align the AFS pump suction source to the backup ESWS source if the primary source is unavailable. This action would involve clearing the pump trips on low suction pressure and opening the motor operated isolation valves on the connections to the ESWS. This is considered reasonable because the backup ESWS is a manually actuated, engineered redundancy of the system. Failure of the operator to initiate backup ESWS has been factored into the fault tree as event HE2.

10.4.9A.4 System Model Qualitative Analysis

The purpose of the system qualitative analysis is to determine the "minimal cut sets", or minimum combinations of events which can lead to the top event. The SETS codes (Reference 10.4.9A-3) which uses top-down Boolean Substitution, was chosen to perform the qualitative analysis because the code allows tree reduction on both cut set order and cut set probability. The Cases 1 and 2 fault trees were individually analyzed to determine its four-or-less event minimal cut sets. The Case 3 fault tree was analyzed to determine its three-or-less event minimal cut sets. The minimal cut sets for each case are summarized as follows:

a) Case 1 (LMFW) - A total of 7530 minimal cut sets were found. There were no one element minimal cut sets and 28, 1017 and 6485 two, three, and four element minimal cut sets, respectively.

b) Case 2 (LMFW/LOOP) - A total of 12015 minimal cut sets were found. There were no one minimal cut sets and 35, 1346 and 10634 two, three, and four element minimal cut sets, respectively.

c) Case 3 (LMFW/SB) - A total of 163 minimal cut sets were found. This total consists of 9 single element, 153 two element and 1 three element minimal cut sets.

10.4.9A.5 System Model Quantitative Analysis

10.4.9A.5.1 Events Causes and Probabilities

To determine overall system unavailability, a probability of occurrence on demand was established for each of the basic events on the fault tree. This was done by identifying the applicable causes (from Section 10.4.9A.2.3) of each event, assigning probabilities to each cause, and summing the cause probabilities to obtain the event probability. Simple arithmetic summing of the cause probabilities was used because the correction terms for simultaneous occurrence would be insignificant because of the small numbers involved. The causes and probabilities of each event entering into the fault tree are given in Table 10.4.9A-3. Reference 10.4.9A-1 was used as the primary source of failure data for the table.

With the exception of testing and maintenance, selection of applicable causes for each event was straightforward. Applicability of test/maintenance causes to each event was determined on a case by case basis through a review of anticipated plant test and maintenance actions. This review is described in detail in Section 10.4.9A.5.1.1.

10.4.9A.5.1.1 Unavailability due to testing and maintenance

System testing/maintenance can contribute to unavailability by two means:

1. Outage - Components/systems are being tested/maintained in an inoperable state at the time operation is demanded.

2. Error - Components realigned for the test/maintenance operation were not re-established to their proper state following the operation by the test/maintenance crew.

A review of the Technical Specifications, ASME Section XI, equipment vendor maintenance manuals, system operating procedures, etc., was conducted to identify testing/maintenance operations, their expected frequency and their potential for unavailability contribution from either outage or error. It should be noted that final Technical Specifications and operating procedures are not yet available for the SHNPP, so typical Technical Specifications and system operating procedures were used. The AFS valves subject to ASME Section XI testing were listed in Table 10.4.9A-4. Table 10.4.9A-5 summarizes maintenance and testing contributions to each component unavailability.

10.4.9A.5.1.1.1 System testing

A discussion of the system tests and their potential contributions to unavailability are given below:

1. PUMPS - The motor driven and turbine driven pumps must be tested in accordance with ASME Section XI subsection IWP, which requires a quarterly test for inlet pressure, Δp, flow rate, and vibration. Subsection IWP also requires a quarterly speed test for the turbine driven pump.

To perform these tests, either of two test methods is used. For the first, the pump is isolated from the steam generators, manually started from the Control Room and allowed to deliver flow back to the CST through the minimum flow recirculation line. If a system demand occurred during the test, the pump being tested would be unavailable because of the closed valve(s). Also, the valve(s) could be left closed after the test. This is included as causing the respective pump to be unavailable.

For the second test method, the AFW pump is started in accordance with normal operating procedures and flow is delivered to the steam generators. Since no system realignment is required for this test, there is no potential for unavailability of the AFW system following a system demand.

The Technical Specifications also require that the pumps be verified to start on an Auxiliary Feedwater Actuation Signal (AFAS) every 18 months (i.e., during a refueling shutdown). This test will be performed by manually initiating the AFAS and observing that the appropriate pumps start. No system valve realignment or temporary wiring arrangements are required. The test is terminated by clearing the AFAS and stopping the pump by turning the control switch to the STOP position then releasing it, allowing it to return to the NORMAL position by spring function to maintain standby conditions. Since the test is performed during plant shutdown and with no system realignment, there is no potential for unavailability from the test either due to outage or error.

2. VALVES - The in-service testing program for SHNPP is listed in FSAR Appendix 3.9D. The valves expected to be subject to testing under ASME Section XI, Subsection IWV are listed in Table 10.4.9A-4.

Subsection IWV requires that these valves be exercised to the position required to fulfill their function every three months. For power operated valves, this includes timing the stroke to assure that valve closure time is within acceptable limits.

For the automatic valves such as the power-operated valves, the test involves opening the valve by turning the control switch and measuring the time the valve requires to stroke as observed by the valve position indicator. The valve is returned to its original position using the control switch. Because the test is brief (lasting only for the stroke time of the valve), valve unavailability due to test outage is very small and was not included in the study.

Each check valve subject to testing can be tested during the testing of the pumps and power operated valves. If a system demand were to occur either during or after testing, the check valve would be returned to its proper position by the fluid forces of the system operation. Thus, testing of the check valves does not contribute to unavailability either by outage or errors.

Monthly inspections are performed to verify that these valves in the flow path for the monthly pump tests are in the open position and, where applicable, are locked.

3. CONTROL CIRCUITS - The Section XI test for pumps and power-operated valves is also a control circuit test. This is a quarterly test for pumps and valves.

4. ACTUATING LOGIC - Details of the testing of the EFAS logic are given in FSAR Section 7.3. As demonstrated there, these tests do not affect generation of the EFAS on demand and thus do not contribute to AFS unavailability.

5. DIESEL GENERATORS - Details of the standby diesel generator testing are given in FSAR Section 8.3. As demonstrated there, tests do not affect the ability of the diesel generators to respond on demand, and thus do not contribute to AFS unavailability.

10.4.9A.5.1.1.2 System maintenance

Maintenance performed during plant operation will be limited such that the result of this maintenance will be improvements to the overall reliability of the Auxiliary Feedwater System. The allowable out-of-service time for the Auxiliary Feedwater System during plant operation is controlled in accordance with Technical Specifications. Unavailability due to system maintenance is normally given by the mean time to repair divided by the mean time between failure for the component. However, the plant Technical Specifications place an upper bound on how long the plant can be operated with the component in repair, so it is appropriate to use a mean time to repair based only on those repairs which take less time than the Technical Specifications LCO for that component. In addition, certain components cannot be repaired during plant operation, so maintenance on these components has no potential for causing unavailability. Details of how maintenance contributes to unavailability for each component is discussed below and a summary listing of maintenance actions affecting each component is given in Table 10.4.9A-5.

a) PUMP MAINTENANCE - This is expected to contribute an outage contribution for the pumps only on the order to 10-4, which is an insignificant addition to the pump probability of failure to start on demand of 5×10^{-3} (including the control circuit). This is believed to be a realistic estimate, but for consistency with Reference 10.4.9A-1 (p. III-16) the following method was used:

$$Q_{MAINT} = .\frac{22\ (maint.act/month)\ x\ 7\ (hrs/maint.act)}{720\ (\text{hrs/month})} = 2.1 \times 10^{-3}$$

Major pump maintenance would require closing the pump discharge and suction isolation valves to permit draining of the pump casing, introducing possible unavailability due to maintenance error, i.e., failure to realign the system properly. This is accounted for in the analysis by assigning a probability that the affected valve(s) is left in the closed position.

b) VALVE MAINTENANCE - Certain AFS valves are not accessible for maintenance during power operation because they directly interface with pressurized systems and cannot be isolated. However, for consistency with Reference 10.4.9A-1, the unavailability from maintenance for power-operated valves was calculated as follows:

$$Q_{MAINT} = .\frac{22\ (maint.act/month)\ x\ 7\ (hrs/maint.act)}{720\ (\text{hrs/month})} = 2.1 \times 10^{-3}$$

Maintenance on valves requires isolation (by closing adjacent valves) of the valve being worked on, introducing the possibility that the valves used for isolation could be left in the closed position. This is accounted for in the analysis by assigning a probability that the affected valve(s) is left in the closed position.

10.4.9A.5.2 System failure probability analysis

The overall system failure probability was determined from the minimal cut sets using the SETS COMTRMVAL procedure. This uses the rare event approximation which neglects the intersection corrections of independent events. Since the probabilities of the basic event in the fault tree are small, the rare event approximation is valid for this study. The results are as follows:

TRANSIENT	$\bar{a}$
CASE 1	$6.6\text{x}10^{-6}$
CASE 2	$6.1\text{x}10^{-5}$
CASE 3	$1.9\text{x}10^{-2}$

10.4.9A.6 Discussion of Results

10.4.9A.6.1 Introduction

The system model quantitative analysis determined the combination of events (minimal cut sets) which can lead to AFS unavailability on demand for the three transients (i.e., LMFW, LMFW/LOOP, and LMFW/SB). All the major minimal cut sets contributing to 0.1 percent or more of the total system unavailability are given in Tables 10.4.9A-6, 10.4.9A-7, and 10.4.9A-8 for the Case-1, Case-2, and Case-3, respectively. The cut sets are sorted according to their failure probabilities and listed. In the system model quantitative analysis probabilities of failure on demand were assigned to basic events and these probabilities of failure on demand were assigned to basic events and these were used to calculate the overall system unavailability from the minimal cut sets. In addition, the SEP code was used to determine the relative contribution of each basic failure event to system unavailability. An event may be considered important if the system unavailability is sensitive to the probability value assigned to that event. The Fussell-Vesely importance measure was used to compute event importances. This measure is equal to the partial derivative of the probability the top event of the fault tree with respect to the probability of the basic event multiplied by the normalized event probability. Tables 10.4.9A-9, 10.4.9A-10, and 10.4.9A-11 provide basic failure events sorted according to the Fussell-Vesely importance measures for the transients, LMFW, LMFW/LOOP and LMFW/SB, respectively.

10.4.9A.6.2 Discussion

CASE 1 - LMFW

a) Minimal Cut Set Importance

Out of 7530 cut sets, 142 cut sets were identified as 0.1 percent or more contributors to the total system unavailability. The dominant cut sets for Case 1 and their relative contributions to system unavailability are given in Table 10.4.9A-6. The total failure probability contributing to 0.1 percent or more of the total system unavailability occupies 86.1 percent of the total system unavailability. The dominant cut sets fall into four basic system failure modes:

1) Failure of one of the valves in the turbine steam supply line (i.e., turbine driven pump failure, turbine steam isolation valve, turbine governing control valve, or turbine stop valve) coupled with both motor driven pump's failures, with one MDP failure and one manual isolation valve failure in the common MDP discharge header, or with failure of two manual isolation valves in the MDP discharge header (24 cut sets). These failure types contribute 39.3 percent of the total system unavailability.

2) Spurious signal generation of any two combined line break isolation signals (12 cut sets). These types contribute 9.6 percent of the total system unavailability.

3) Failure of one of the pressure control valves coupled, with failure of one of the valves in the turbine steam supply line (i.e., turbine driven pump failure, turbine steam isolation valve, turbine governing control valve, or turbine stop valve) and opposite one MDP failure against the corresponding pressure control valve, or with failure of one of the manual isolation valves in the MDP discharge header and failure of one of the turbine steam supply line valves (16 cut sets). These types contribute 11.0 percent of the total system unavailability.

4) Failure of one of the flow control valves in MDP discharge header coupled with turbine steam isolation valve failure and failure of one of the manual isolation valves in the MDP discharge header (6 cut sets). These types contribute 5.4 percent of the total system unavailability.

The above failure modes account for 65.3 percent of the total system unavailability. The remaining 34.7 percent is from 7472 cut sets with lesser importance.

b) Basic Event Importance

The basic events for Case 1 are listed according to the importance in Table 10.4.9A-9. The dominant important failure events are: turbine steam isolation valve failure, MDP "A" or "B" failure, TDP failure, failures of manual isolation valves in the MDP discharge header, turbine stop valve failure, turbine governing control valve failure, failures of flow control valves in the MDP discharge header, failures of manual isolation valves in the common MDP discharge header, spurious line break isolation signals, and failure of pressure control valves. The remaining events are relatively less important than those discussed above.

The point estimate of AFS unavailability for Case 1 is $6.6x10^{-6}$, which is beyond the high unavailability range of Reference 10.4.9A-1 (unavailability between 10^{-4} AND 10^{-5}).

CASE 2 - LMFW/LOOP

a) Minimal Cut Set Importance

Out of 12015 cut sets, 64 cut sets were identified as 0.1 percent or more contributors to the total system unavailability. The dominant cut sets for Case 2 and their relative contributions to system unavailability are given in Table 10.4.9A-7. The total failure probability contributing to 0.1 percent or more of the total system unavailability occupies 91.4 percent of the total system unavailability. The dominant cut sets fall into the following system failure modes:

1) Failure of one of the valves in the turbine steam supply line (i.e., turbine driven pump failure, turbine steam isolation valve, turbine governing control valve, or turbine stop valve) coupled with 6.9KVAC "A" and "B" failures (3 cut sets). These failure types contribute 27.6 percent of the total system unavailability.

2) Failure of 6.9KVAC "A" coupled with 125VDC "B" failure (1 cut set). This type contributes 13.1 percent of the total system unavailability.

3) Failure of the TDP suction isolation valve coupled with 6.9KVAC "A" and "B" failure (1 cut set). This type contributes 11.1 percent of the total system unavailability.

4) Failure of 6.9KVAC "A" or "B" coupled with two other various basic events (32 cut sets). These types contribute 30.2 percent of the total system unavailability. However, these types are less important than the above three (a, b, and c) failure modes if number of cut sets are considered.

The above failure modes account for 82.0 percent of the total system unavailability. The remaining 18.0 percent is from over 11978 cut sets with lesser importance.

b) Basic Event Importance

The basic events for Case 2 are listed according to the importance in Table 10.4.9A-10. The dominant important failure events are: 6.9KVAC "A" or "B" failure, turbine steam isolation valve failure, 125VDC "B" failure, TDP failure, turbine governing control or stop valve failure, TDP suction isolation valve failure, MDP "A" failure, MDP "B" failure, failures of manual isolation valves in the MDP common discharge header, failures of MDP suction isolation valves, and failures of pressure control valves. The remainder events are relatively less important than those discussed above.

The point estimate of AFS unavailability for Case 2 is $6.1x10^{-5}$, which is in the high availability range of Reference 10.4.9A-1 (unavailability between 10^{-4} and 10^{-5}).

CASE 3 - LMFW/SB

a) Minimal Cut Set Importance

Out of 163 cut sets, 12 cut sets were identified as 0.1 percent or more contributors to the total system unavailability. The dominant cut sets for Case 3 and their relative contributions to system unavailability are given in Table 10.4.9A-8. The total failure probability contributing to 0.1 percent or more of the total system unavailability occupies 97.3 percent of the total system unavailability.

The dominant cut sets are:

1) Failure of turbine steam isolation valve (1 cut set). This type contributes 26.8 percent of the total system unavailability.

2) Failure of TDP suction isolation valve (1 cut set). This type contributes 26.8 percent of the total system unavailability.

3) TDP failure (1 cut set). This type contributes 16.3 percent of the total system unavailability.

4) Failure of turbine governing control or stop valve (1 cut set each). Each type contributes 12.1 percent to the total system unavailability.

The above four failure modes account for 94.1 percent of the total system unavailability. The remaining 5.9 percent from 158 cut sets are less important than the above four failure modes.

b) Basic Event Importance

The basic events for Case 3 are listed according to the importance in Table 10.4.9A-11. The dominant important failure events are: failure of TDP suction or steam supply isolation valve, TDP failure, and failure of turbine stop or governing control valve. The remaining events are relatively less important than those discussed above.

The point estimate of AFS unavailability for Case 3 is 1.9×10^{-2}, which is in the medium availability range of Reference 10.4.9A-1 (unavailability between 10^{-1} and 10^{-2}).

10.4.9A.7 Conclusions

The SHNPP AFS exhibited a very high availability. The main reasons favorable results were achieved are:

a) The active components and flow paths are redundant, so there are no single point vulnerabilities.

b) The system is automatically actuated, so no human action is required.

c) Most system valves are normally aligned to their operational state, and thus require no transition to achieve the system function.

d) The MDP's have flow control and isolation valves which are separate from those of the TDP.

This analysis did not uncover any areas where minor changes could result in major availability improvements. In fact, calculated system availability is so high that common cause failures from external events outside the scope of this study are probably the dominant cause of system failure in actuality. Thus, even major system changes (e.g., adding more pumps) would have little effect on true system availability. Availability has always been a qualitative consideration in the design of the SHNPP AFS, and this study confirmed that.

REFERENCES: APPENDIX 10.4.9A

10.4.9A-1 "Actions required from operating license applicants of nuclear steam supply systems designed by Westinghouse and Combustion Engineering resulting from the NRC Bulletins and Orders Task Force review regarding the Three Mile Island Unit 2 accident," letter from D. F. Ross to all Westinghouse and Combustion Engineering Operating License Applicants, Division of Project Management, Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission, March 10, 1980.

10.4.9A-2 Reactor Safety Study, Appendices III and IV, WASH-1400 (NUREG-75/014), Nuclear Regulatory Commission, October 1975.

10.4.9A-3 Set Equation Transformation System (SETS), as described in NUREG/CR-0465, "A SETS User's Manual for the Fault Tree Analyst," Richard B. Worrell and Desmond W. Stack, November 1978.

APPENDIX 10.4.9B CP&L RESPONSE TO ENCLOSURE 2 OF NRC LETTER OF MARCH 10, 1980 – "BASIS FOR AUXILIARY FEEDWATER SYSTEM FLOW REQUIREMENTS" – REVISION 1

10.4.9B.0 Introduction

By letter dated March 10, 1980 the NRC requested information from all operating license applicants with regard to the Auxiliary Feedwater System (AFS) in light of the events at Three Mile Island Unit 2. Enclosure 2 to the letter (addressed in this appendix) is concerned with the design basis for the AFS flow (compliance with the requirements of SRP 10.4.9 and BTP ASB-10-1).

This appendix incorporates the information submitted to the staff in support of the SHNPP AFS design. The information presented in this chapter is considered a historical record and may not reflect the latest AFS design.

10.4.9B.1 NRC Item 1A

Identify the plant transients and accident conditions considered in establishing AFS flow requirements.

a) Loss of main feed (LMFW).

b) LMFW with loss of off-site AC power.

c) LMFW with loss of on-site and off-site AC power.

d) Plant cooldown.

e) Turbine trip with and without bypass.

f) Main steam isolation valve closure.

g) Main feedline break.

h) Main steamline break.

i) Small break LOCA.

j) Other transient or accident conditions not listed above.

10.4.9B.1.1 CP&L response to NRC Item 1A

The Auxiliary Feedwater System serves as a backup system for supplying feedwater to the secondary side of the steam generators at times when the feedwater system is not available, thereby maintaining the heat sink capabilities of the steam generators. As an Engineered Safeguards System, the Auxiliary Feedwater System is directly relied upon to prevent core damage and system overpressurization in the event of transients, such as loss of normal feedwater or a secondary system pipe rupture and to provide a means for plant cooldown following any plant transient.

Following a reactor trip, decay heat is dissipated by evaporating water in the steam generators and venting the generated steam either to the condensers through the steam dump or to the atmosphere through the steam generator safety valves or the power-operated relief valves. Steam generator water inventory must be maintained at a level sufficient to ensure adequate heat transfer and continuation of the decay heat removal process. The water level is maintained under these circumstances by the Auxiliary Feedwater System, which delivers an emergency water supply to the steam generators. The Auxiliary Feedwater System must be capable of functioning for extended periods allowing time either to restore normal feedwater flow or to proceed with an orderly cooldown of the plant to the reactor coolant temperature where the Residual Heat Removal System can assume the burden of decay heat removal. The Auxiliary Feedwater System flow and the emergency water supply capacity must be sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown. The Auxiliary Feedwater System can also be used to maintain the steam generator water levels above the tubes following a LOCA. In the latter function, the water head in the steam generators serves as a barrier to prevent leakage of fission products from the Reactor Coolant System into the secondary plant.

10.4.9B.1.1.1 Design Considerations

The reactor plant conditions, which impose safety-related performance requirements on the design of the Auxiliary Feedwater System, are as follows for the SHNPP:

a) Loss of main feedwater transient.

   1) with off-site power available

    2) without off-site power available.

b) Secondary system pipe ruptures

    1) feedline rupture

    2) steamline rupture.

c) Loss of coolant accident (LOCA).

d) Loss of all AC power.

e) Cooldown.

10.4.9B.1.1.1.1 Loss of Main Feedwater Transients

The design loss of main feedwater transients are those caused by:

a) Interruptions of the Main Feedwater System flow due to a malfunction in the feedwater or condensate system.

b) Loss of off-site power or blackout with the consequential shutdown of the system pumps, auxiliaries, and controls.

Loss of main feedwater transients are characterized by a rapid reduction in steam generator water levels which results in a reactor trip, a turbine trip, and auxiliary feedwater actuation by the protection system logic. Following reactor trip from high power, the power quickly falls to decay heat levels. The water levels continue to decrease progressively uncovering the steam generator tubes as decay heat is transferred and discharged in the form of steam either through the steam dump valves to the condenser or through the steam generator safety or power-operated relief valves to the atmosphere. The reactor coolant temperature increases as the residual heat in excess of that dissipated through the steam generators is absorbed. With increased temperature, the volume of reactor coolant expands and begins filling the pressurizer. Without the addition of sufficient emergency feedwater, further expansion will result in water being discharged through the pressurizer safety and relief valves. If the temperature rise and the resulting volumetric expansion of the primary coolant are permitted to continue, then 1) pressurizer safety valve capacities may be exceeded causing overpressurization of the Reactor Coolant System and/or 2) the continuing loss of fluid from the primary coolant system may result in bulk boiling in the Reactor Coolant System and eventually in core uncovering, loss of natural circulation, and core damage. If such a situation were ever to occur, the Emergency Core Cooling System would be ineffectual because the primary coolant system pressure exceeds the shut-off head of the safety injection system pumps, the nitrogen overpressure in the accumulator tanks, and the design pressure of the Residual Heat Removal Loop. Hence, the timely introduction of sufficient emergency feedwater is necessary to arrest the decrease in the steam generator water levels to reverse the rise in reactor coolant temperature, to prevent the pressurization from filling to a water solid condition, and eventually to establish stable hot standby conditions. Subsequently, a decision may be made to proceed with plant cooldown if the problem cannot be satisfactorily corrected.

The blackout transient differs from a simple loss of main feedwater in that emergency power sources must be relied upon to operate vital equipment. The loss of power to the electric-driven condenser circulating water pumps results in a loss of condenser vacuum and condenser dump valves. Hence, steam formed by decay heat is relieved through the steam generator safety valves or the power-operated relief valves. The calculated transients are similar for both the loss of main feedwater and the blackout except that reactor coolant pump heat input is not a consideration in the blackout transient following loss of power to the reactor coolant pump bus.

10.4.9B.1.1.1.2 Secondary System Pipe Ruptures

The feedwater line rupture accident not only results in the loss of feedwater flow to the steam generators, but also results in the complete blowdown of one steam generator within a short time if the rupture should occur downstream of the last nonreturn valve in the main feedwater piping to an individual steam generator. Another significant result of a feedline rupture may be the spilling of auxiliary feedwater from the faulted steam generator. This could result in the pumping of a disproportionately large fraction of the total emergency feedwater flow to the faulted steam generator and out the break because the system preferentially pumps water to the lowest pressure steam generator rather than to the effective steam generators which are at relatively high pressure. The system design must allow for terminating, limiting, or minimizing that fraction of emergency feedwater flow which is delivered to a faulted loop in order to ensure that sufficient flow will be delivered to the remaining effective steam generator(s). The concerns are similar for the main feedwater line rupture as those explained for the loss of main feedwater transients.

Main steamline rupture accident conditions are characterized initially by plant cooldown, and for breaks inside containment, by increasing containment pressure and temperature. Auxiliary feedwater is not needed during the early phase of the transient, but flow to the faulted loop will contribute to the release of mass and energy to containment. Thus, steamline rupture conditions establish the upper limit on auxiliary feedwater flow delivered to a faulted loop. Eventually, however, the Reactor Coolant System will heat up again and emergency feedwater flow will be required to be delivered to the unfaulted loops but at somewhat lower rates than for the loss of feedwater transients described previously. Provisions must be made in the design of the Auxiliary Feedwater System to limit, control, or terminate the auxiliary feedwater flow to the faulted loop as necessary in order to prevent containment overpressurization following a steamline break inside containment and to ensure the minimum flow to the remaining unfaulted loops.

10.4.9B.1.1.1.3 Loss-of-Coolant Accident (LOCA)

The loss of coolant accidents do not impose on the emergency feedwater system any flow requirements in addition to those required by the other accidents addressed in this response. The following description of the small LOCA is provided here for the sake of completeness to explain the role of the Auxiliary Feedwater System in this transient.

Small LOCAs are characterized by relatively slow rates of decrease in reactor coolant system pressure and liquid volume. The principal contribution from the Auxiliary Feedwater System following such small LOCAs is basically the same as the system's function during hot shutdown or following a spurious safety injection signal which trips the reactor. Maintaining a water level inventory in the secondary side of the steam generators provides a heat sink for removing decay heat and establishes the capability for providing a buoyancy head for natural circulation.

The Auxiliary Feedwater System may be utilized to assist in a system cooldown and depressurization following a small LOCA while bringing the reactor to a cold shutdown condition.

10.4.9B.1.1.1.4 Cooldown

The cooldown function performed by the Emergency Feedwater System is a partial one since the reactor coolant system is reduced from normal zero load temperatures to a hot leg temperature of approximately 350F. The latter is the maximum temperature recommended for placing the Residual Heat Removal System (RHRS) into service. The RHR system completes the cooldown to cold shutdown conditions.

Cooldown may be required following expected transients following an accident such as a main feedline break, or during a normal cooldown prior to refueling or performing reactor plant maintenance. If the reactor is tripped following extended operation at rated power level, the EFS is capable of delivering sufficient emergency feedwater to remove decay heat and reactor coolant pump (RCP) heat following reactor trip while maintaining the steam generator (SG) water level. Following transients or accidents, the recommended cooldown rate is consistent with expected needs and at the same time does not impose additional requirements on the capacities of the emergency feedwater pumps considering a single failure. In any event, the process consists of being able to dissipate plant sensible heat in addition to the decay heat produced by the reactor core.

10.4.9B.1.1.1.5 Loss of All AC Power

The loss of all AC power is postulated as resulting from accident conditions wherein not only on-site and off-site AC power is lost but also AC emergency power is lost as an assumed common mode failure. Battery power for operation or protection circuits is assumed available. The impact on the Auxiliary Feedwater System is the necessity for providing both an auxiliary feedwater pump power and control source which are not dependent on AC power and which are capable of maintaining the plant at hot shutdown until AC power is restored.

10.4.9B.2 NRC Item 1B

Describe the plant protection acceptance criteria and corresponding technical bases used for each initiating event identified in Section 10.4.9B.1. The acceptance criteria should address plant limits, such as:

a) Maximum RCS pressure (PORV or safety valve actuation).

b) Fuel temperature or damage limits (DNB, PCT, maximum fuel central temperature).

c) RCS cooling rate limit to avoid excessive coolant shrinkage.

d) Minimum steam generator level to assure sufficient steam generator heat transfer surface to remove decay heat and/or cooldown the primary system.

10.4.9B.2.1 CP&L Response to NRC Item 1B

Table 10.4.9B-1 summarizes the criteria, which are the general design bases for each event discussed in Section 10.4.9B.1. Specific assumptions used in the analyses to verify that the design bases are met are discussed in Section 10.4.9B.3.1.

The primary function of the Auxiliary Feedwater System is to provide sufficient heat removal capability for heatup accidents following reactor trip to remove the decay heat generated by the core and prevent system overpressurization. Other plant protection systems are designed to meet short-term or pretrip fuel failure criteria. The effects of excessive coolant shrinkage are bounded by the analysis of the rupture of a main steam pipe transient. The maximum flow requirements determined by other bases are incorporated into this analysis resulting in no additional flow requirements.

10.4.9B.3 NRC Item 2

Describe the analyses and assumptions and corresponding technical justification used with plant condition considered in Section 10.4.9B.2 including:

a) Maximum reactor power (including instrument error allowance) at the time of the initiating transient or accident.

b) Time delay from initiating event to reactor trip.

c) Plant parameter(s) which initiates AFW flow and time delay between initiating event and introduction of AFW flow into steam generator(s).

d) Minimum steam generator water level when initiating event occurs.

e) Initial steam generator water inventory and depletion rate before and after AFW flow commences - identify reactor decay heat rate used.

f) Maximum pressure at which steam is released from steam generator(s) and against which the AFW pump must develop sufficient head.

g) Minimum number of steam generators that must receive AFW flow; e.g., one out of two? Two out of four?

h) RC flow condition - continued operation of RC pumps or natural circulation.

i) Maximum AFW inlet temperature.

j) Following a postulated steam or feedline break, time delay assumed to isolate break and direct AFW flow to intact steam generator(s). AFW pump flow capacity allowance to accommodate the time delay and maintain minimum steam generator water level. Also identify credit taken for primary system heat removal due to blowdown.

k) Volume and maximum temperature of water in main feed lines between steam generator(s) and AFS connection to main feed line.

l) Operating condition of steam generator normal blowdown following initiating event.

m) Primary and secondary system water and metal sensible heat used for cooldown and AFW flow sizing.

n) Time at hot standby and time to cooldown RCS to RHR system cut in temperature to size AFW water source inventory.

10.4.9B.3.1 CP&L Response to NRC Item 2

The limiting transients which define the AFS performance requirements for SHNPP are as follows:

a) Loss of main feedwater (station blackout).

b) Rupture of main feedwater pipe.

c) Rupture of main steam pipe inside containment.

d) Plant cooldown.

10.4.9B.3.1.1 Loss of Main Feedwater (Blackout)

A loss of feedwater assuming a loss of power to the reactor coolant pumps was performed in FSAR Section 15.2.6 for the purpose of showing that for a station blackout transient, one auxiliary feedwater pump delivering flow to two steam generators does not result in filling the pressurizer. Furthermore, the peak RCS pressure remains below the criterion for Condition II transients and no fuel failure occurs (refer to Table 10.4.9B-1). Table 10.4.9B-2 summarizes the assumptions used in this analysis. The transient analysis begins at the time of reactor trip. This can be done because the trip occurs on a steam generator level signal; hence, the core power, temperatures, and steam generator level at time of reactor trip do not depend on the event sequence prior to trip. Although the time from the loss of feedwater until the reactor trip occurs cannot be determined from this analysis, this delay is expected to be 20 to 30 seconds. The analysis assumes that the plant is initially operating at 102% of the Engineered Safeguards Design (ESD) rating shown on the table, a very conservative assumption in defining decay heat and stored energy in the RCS. The reactor is assumed to be tripped on low-low steam generator level allowing for level uncertainty.

10.4.9B.3.1.2 Rupture of Main Feedwater Pipe

The double-ended rupture of a main feedwater pipe downstream of the main feedwater line check valve is analyzed in FSAR Section 15.2.8. Table 10.4.9B-2 summarizes the assumptions used in this analysis. Reactor trip is assumed to be actuated by low-low level in the affected steam generator. This conservative assumption maximizes the stored heat prior to reactor trip and minimizes the ability of the steam generator to remove heat from the RCS following reactor trip due to a conservatively small total steam generator inventory. As in the loss of normal feedwater analysis, the initial power rating was assumed to be 102% of the ESD rating. The SHNPP auxiliary feedwater design is assumed to supply a total of 286 gpm to two intact steam generators prior to automatic AFW isolation, and 430 gpm to the two intact steam generators after AFW isolation of the affected steam generator. The criteria listed in Table 10.4.9B-1 are met.

10.4.9B.3.1.3 Rupture of a Main Steam Pipe Inside Containment

Because the steamline break transient is a cooldown, the AFS is not needed to remove heat in the short term. Furthermore, addition of excessive emergency feedwater to the faulted steam generator will affect the peak containment pressure following a steamline break inside containment. This transient is performed at four power levels for several break sizes. Emergency feedwater is assumed to be initiated at the time of the break independent of the system actuation signals. The maximum flow is used for this analysis. Table 10.4.9B-2 summarizes the assumptions used in this analysis. The criteria stated in Table 10.4.9B-1 are met.

This transient establishes the maximum allowable emergency feedwater flow rate to a single-faulted steam generator assuming all pumps operating; establishes the basis for runout protection, if needed; and establishes layout requirements so that the flow requirements may be met considering the worst single failure.

10.4.9B.3.1.4 Plant Cooldown

Maximum and minimum flow requirements from the previously discussed transients meet the flow requirements of plant cooldown. This operation, however, defines the basis for tankage size based on the required cooldown duration, maximum decay heat input, and maximum stored heat in the system. As previously discussed in Section 10.4.9B.1.1 the emergency feedwater system partially cools the system to the point where the RHRS may complete the cooldown; i.e., 350F in the RCS. Table 10.4.9B-2 shows the assumptions used to determine the cooldown heat capacity of the emergency feedwater system.

The cooldown is assumed to commence at 102% of engineered safeguards design power; and maximum trip delays and decay heat source terms are assumed when the reactor is tripped. Primary metal, primary water, secondary system metal, and secondary system water are all included in the stored heat to be removed by the AFS. See Table 10.4.9B-3 for the items constituting the sensible heat stored in the NSSS.

This operation is analyzed to establish minimum tank size requirements for emergency feedwater fluid source which is normally aligned.

10.4.9B.4 NRC Item 3

Verify that the AFW pumps in your plant will supply the necessary flow to the steam generators as determined by Items 1 and 2 above considering a single failure. Identify the margin in sizing the pump flow to allow for pump recirculation flow, seal leakage, and pump wear.

10.4.9B.4.1 CP&L Response to NRC Item 3

The AFW pumps in the SHNPP AFS design will supply the required flow to the steam generators considering single failure. The two 100% capacity motor-driven pumps are sized for 450 gpm each and are capable of delivering 490 gpm. The turbine-driven pump (200%

capacity) is sized to deliver 900 gpm. Thus, for Condition IV events, the AFS has the capability of supplying 200% of the required flow even with a failure of the largest pump.

TABLE 10.1.0-1

SUMMARY OF IMPORTANT DESIGN AND PERFORMANCE CHARACTERISTICS OF THE STEAM AND POWER CONVERSION SYSTEM

Nuclear Steam Supply System (NSSS) at 100% rated condition.

Thermal Power = 2960.4 Mwt (RCS Tavg 588.8°F)
Steaming rate: 13.10×10^6 lb./hr.
Conditions at steam generator outlet:
Pressure 1004 psia
Moisture 0.1%
Temperature 542.0°F
Enthalpy 1192.1 Btu/lbm.

Turbine Generator Unit
(Section 10.2)

1. Turbine data

   Estimated Throttle Flow at 100% Thermal Power: 12.03×10^6 lb./hr.

   Steam conditions at turbine throttle valves:

	press (psia)	enthalpy (Btu/lb.)	temperature (F)	moisture (%)
design maximum	982	1192.1	542	0.2

   a. Frame 4448ET3
   b. Type/LSB length (in.) TC4F-45
   c. No. of cylinders 1-HP, 2-LP
   d. Shaft Speed (rpm) 1800

2. Turbine cycle arrangement:
   a. Moisture-separator/reheaters 2 shells -1 heating stage
   b. No. of extractions - LP turbine 3
   c. No. of extractions - HP turbine 2

3. Generator –

	Original Rated Conditions	Maximum Design Load Conditions
a. Output (kVa)	1,145,000	1,155,000
b. Calculated Gross output (kW)	954,303	1,085,700
c. Power Factor	0.91	0.94
d. Voltage (volts)	22000	22000
e. Phase/Frequency (Hz)	3/60	3/60
f. Hydrogen pressure (psig)	75	75
g. Static gas volume (ft.^{3})	3,800	3,800

Table 10.1.0-1 (Continued)

Main Steam System
(Section 10.3)

1. Piping from each steam generator up to and including the main steam isolation valves is safety related and designed to ASME Section III Class 2, Seismic Category I.
2. Piping from main steam to the emergency feedpump turbine is safety related and designed to ASME Section III Class 2 and Class 3, Seismic Category I.
3. All other main steam piping is designed to ANSI B31.1. Piping between the MSIV and the last seismic restraint in the Turbine Building is Seismic Category I.
4. Main steam isolation valve is safety related and designed to ASME Section III Class 2, seismic Category I. Closure time is specified in Table 10.3.1-1.
5. Main steam safety valves and power operated atmospheric dump valves are safety related, designed to ASME Section III Class 2, Seismic Category I. Capacities are specified in Table 10.3.1-1.

Condenser
(Section 10.4.1)

The condenser is a single shell multipressure single pass deaerating type condenser. The condenser is located below the two low pressure sections of the turbine. Condenser expected backpressures at maximum design load in the individual zones are 4.49 and 5.93 in. Hg with a cooling water inlet temperature at 98.7°F.

The condenser is designed to be able to accept steam from the turbine bypass system up to 40% of maximum design load. The condenser tubes are oriented parallel to the turbine axis.

Condenser Evacuation System
(Section 10.4.2)

Two (2) 100% capacity mechanical vacuum pumps are provided. Each pump is suitable for both condenser hogging and holding. Effluent gas is monitored for radioactivity and processed, as required, by the Condenser Vacuum Pump Effluent Treatment System (CVPETS).

Turbine Gland Sealing System
(Section 10.4.3)

Supplied by main steam or auxiliary steam. The gland steam condenser receives condensate flow for cooling gland and turbine valve stem low pressure leak-off flows.

Steam Dump System
(Section 10.4.4)

The Steam Dump System in combination with the reactor fast cut back capability is designed to be able to accept a full electrical load drop without tripping the reactor. While being able to tolerate a 100% electrical load rejection without tripping the reactor is no longer a design basis for Harris Plant, the Steam Dump System design maintains the capacity as was originally designed.

Condensate Polishing Demineralizer System
(Section 10.4.6)

Full flow condensate polishing demineralizer with 6 vessels - 5 operating, 1 standby, to maintain feedwater purity consistent with steam generator requirements.

Table 10.1.0-1 (Continued)

Condensate and Feedwater System
(Section 10.4.7)

1.	Number of Feedwater Heating Stages	5
2.	Feedwater Heater Stages in Condenser Neck	1
3.	Feedwater Heater Stages Outside Neck	4
4.	No. Condensate Pumps	2
5.	No. Condensate Booster Pumps	2
6.	No. SGFP - Motor Driven	2
7.	No. Heater Drain Pumps	2 (Pumps forward from heater to steam generator feedwater pump suction)
8.	Feedwater Cleanup Recirculation	Connection from feedwater header downstream of high press feedwater heaters No. 5 to condenser hotwell.
9.	Main Feedpump Discharge Piping to FWIV	
	Design Pressure, psig	1955
	Design Temperature, F	450
	Valve Pressure Rating, lb.	900
10.	Valve Stroke Time, Sec.	
	FWIV-Fast Closure	8, maximum
	FW Control - Modulating	20
	FW Control - Fast Closure	8, maximum

SG Blowdown System
(Section 10.4.8)

Designed for 2 percent rated steam flow (maximum) with flash tank for steam heat recovery. Liquid effluent is piped through blowdown heat recovery and cleanup to condenser.

Auxiliary Feedwater System
(Section 10.4.9)
One turbine driven and two motor driven pumps. The auxiliary feed pumps are capable of supplying to the steam generators 475 gpm each from the two motor driven pumps and 900 gpm from the turbine driven pump. The two motor-driven auxiliary feedwater pumps have a design capacity of 450 gpm but can provide more than 475 gpm with their recirculation lines closed. Piping and components are safety related and designed to ASME Section III Class 2 or Class 3 as appropriate.

TABLE 10.2.1-1

TURBINE GENERATOR UNIT

a) Turbine data

Throttle flow at maximum design load condition 12.03 x 10^6 lb./hr.

Steam conditions at turbine throttle valves.

	press psia	enthalpy Btu/lb.	temperature F	moisture %
Maximum Design Load	982	1192.1	542.0	0.2

Turbine back pressures (in Hg abs)

Zone 1 2.99

Zone 2 4.13

1)	Frame	4448 ET3
2)	Type/LSB length (in.)	TC4F-45
3)	No. of cylinders	1-HP, 2-LP
4)	Shaft speed (rpm)	1800

b) Turbine cycle arrangement

1)	Moisture-separator/reheaters	2 shells - 1 stage reheat
2)	No. of extractions - LP turbine	3
3)	No. of extractions - HP turbine	2

c) Generator

	Original Rated Conditions	Maximum Design Load Conditions
Output (kVa)	1045,000	1,155,000
Calculated Gross Output (kW)	954,303	1,085,700
Power Factor	0.91	0.94
Voltage (volts)	22,000	22,000
Phase/Frequency (Hz)	3/60	3/60
Hydrogen pressure (psig)	75	75

TABLE 10.3.1-1

MAIN STEAM SYSTEM DESIGN PARAMETERS

a)	Main Steam System Conditions	
	Design Pressure, psia	1200
	Design Temperature, °F	600
	Design Steam Flow, lb/hr	13.10×10^6
	Normal Operating Pressure psia	1011
	Normal Operating Temperature F	545.9
	Turbine Throttle Valve Normal Inlet Pressure, psia	982
	Turbine Throttle Valve Normal Inlet Temperature, F	542
b)	Piping	
	No. of M.S. Lines	3
	M.S. Line ID, in.	30
	Code (up to MSIV)	ASME III, Class 2
	Seismic Category (up to last seismic restraint)	I
c)	Main Steam Isolation Valve	
	Quantity	3
	Type	Y
	Closing, Time max, sec.	5
	Actuator Type	Pneumatic spring to close
	Code	ASME III, Class 2
	Seismic Category	I
d)	Main Steam Line Safety Valves	
	Number of main steam lines	3
	Number of valves per main steam line	5
	Total number of safety valves	15
e)	Operated Relief Valve	
	Quantity	3
	Number of valves per main steam line	1
	Max. Allowable Steam Flow, each valve, lb/hr.	970,000 @ 1200 psia
	Min. required Steam Flow, each valve lb./hr.	64,000 @ 100 psia 795,000 @ 1200 psig
	Stroke Time, sec.	20 (Modulating)
	Closing time, max., sec.	15
	Type	Drag
	Actuator	Electro Hydraulic
	Code	ASME III, Class 2
	Seismic Category	I
f)	Main Steam Isolation Valve Bypass Valve	
	Quantity	3
	Number of Valves per Main Steam Line	1
	Maximum Steam Flow, lb/hr.	60,000
	Closing time, max, sec.	10
	Actuator Type	Pneumatic spring to close
	Code	ASME III, Class 2
	Seismic Category	I

Table 10.3.1-1 (Continued)

Design Data for Safety Valves in Each Main Steam Line

Valve No. Line from Stm Gen #A	Valve No. Line from Stm Gen #B	Valve No. Line from Stm Gen #C	Set Pressure (psig)	Flow* (lbs/hr/valve)
2MS-R1SA	2MS-R2SB	2MS-R3SA	1170	881,980
2MS-R4SA	2MS-R5SB	2MS-R6SA	1185	893,160
2MS-R7SA	2MS-R8SB	2MS-R9SA	1200	904,330
2MS-R10SA	2MS-R11SB	2MS-R12SA	1215	915,500
2MS-R13SA	2MS-R14SB	2MS-R15SA	1230	926,670
			Total Flow (each line)	4,521,640

Maximum Allowable flow from a safety valve lb/hr/valve (at an accumulation pressure of 1278 psig)	970,000
Maximum Allowable Steam Generator Pressure, psia	1320
Steam Line Pressure Drop from Stm. Gen. to Safety Valves at Total Capacity, psi	15.1
Maximum Allowable Accumulation, to valve full open, %	3
Set Pressure Error, % max.	3
Code	ASME III, Class 2
Seismic Category	I

Main Steam System Valve Material Specification

MS Safety Valves:
Body; ASME-SA105
Bonnet; ASME-SA105
Nozzle; ASME-SA182 F-316
Bonnet Stud; ASME-SA193 GR B7
Bonnet Stud Nut; ASME-SA194 GR 2H

MS Power Operated Relief Valves:
Body; ASME-SA105
Bonnet; Plain Bolted ASME-SA105
Plug; ASME-SA 182 F11/STELL. #6
Stem; ASME-SA 479 410/MICRO PLATE #1-C

* Capacity at full (3%) accumulation

TABLE 10.3.2-1

MAIN STEAM FLOW RATES

BRANCH-OFF FLOW PATH DESCRIPTION	MAXIMUM STEAM FLOW lbs./hr x 10^3	TYPE OF VALVE(S) (NORMAL POSITION)	SIZE OF VALVE(S)	QUALITY OF VALVE(S)	DESIGN CODE OF VALVES	CLOSURE TIME OF THE VALVES	ACTUATION MECHANISM OF VALVE(S)	POWER SOURCE OF VALVE(S)
Steam Dump to Atmosphere								
1. Eight (8) Control Valves	772* (Each)	Globe (Closed)	8”	NNS	ASME Section III	5 Sec. Quick Close 20 Sec. Modulating	Diaphragm	Air
2. Eight (8) Block Valves	772* (Each)	Gate (Locked Open)	8”	NNS	B31.1	NA	Hand	NA
Steam Dump to Condenser								
Six (6) Control Valves	772* (Each)	Globe (Closed)	8”	NNS	ASME Section III	5 Sec. Quick Close 20 Sec. Modulating	Diaphragm	Air
Glad Seal Supply	16	Globe (Locked Open)	4”	NNS	B31.1	NA	Hand	NA
MSR Supply to:								
1. Control Valves	1150	Globe (Open)	12”	NNS	B31.1	65 Sec.	Diaphragm	Air
2. & Bypass Control Valves	1150	Globe (Open)	4”	NNS	B31.1	11 Sec.	Diaphragm	Air
3. Shutoff Valves (Motor)	1150	Globe (Open)	12”	NNS	B31.1	115 Sec.	Motor	AC
		Globe (Open)	6”	NNS	B31.1	28 Sec.	Motor	AC
Block Valves (Manual)	1150	Globe (Open)	12”/6”	NNS	B31.1	NA	Hand	NA
Back-up Auxiliary Steam Supply	117	Gate (Closed)	6”	NNS	B31.1	34 Sec.	Motor	AC
Miscellaneous Vents & Drains	--	Globe (Closed)	1”	NNS	B31.1	NA	Hand	NA
		Globe (Closed)	1” and 2”	NNS	B31.1	5 Sec. Max.	Diaphragm	Air

*Lowest maximum flow value for the entire set of dump valves which resulted from a valve inlet pressure of 964.6 psia & a full load pressure of 1011 psia at the SG outlet.

TABLE 10.4.1-1

MAIN CONDENSER EQUIPMENT DATA

a)	Number of condenser shells	1
b)	Cooling surface, sq. ft.	595,000
c)	Condenser pressure (in Hg. abs) zone 1/2	3.72/5.21**
d)	Tube cleanliness factor, percent	85.0
e)	Circulating water flow (gpm)	487,600**
f)	Number of water passes	1
g)	Design inlet temperature of circulating water (F)	95.2**
h)	Design outlet temperature of circulating water (F)	122.4**
i)	Operating range (in Hg. abs) zone 1/2	$\frac{1.35^{*} - 3.80}{2.90^{*} - 5.30}$
j)	Condenser tube materials	Sea-Cure (ASTM A268UNS S44660)
k)	Tube Sheet Material	Aluminum Bronze
l)	Condenser Tubes	
1)	Number	32,568
2)	Size, in.	1.00 O.D.
3)	Gauge, BWG	22
4)	Active Length, ft.	70.156

*Condenser pressure based on 50% cooling water during winter.

**Parameter represents expected performance

TABLE 10.4.1-2

CONDENSER INDICATION AND ALARMS

EQUIPMENT	INSTRUMENTATION	LOCATION	INITIATING SIGNAL
Condenser 1A	Computer Indication	Computer Computer Room	FT-1901
Condenser 1A	Pressure Indication PI-1900 A	Main Control Board (MCB) Main Control Room	PT-1900A
Condenser 1A Zone 1	Computer Indication	Computer Computer Room	TE-1900A
Condenser 1A Zone 1	Computer Indication	Computer Computer Room	PT-1900A
Condenser 1A Zone 1	Level Gage LG-1900A	Local	-
Condensate to Storage Tank	Computer Indication	Computer Computer Room	FT-1900
Condenser 1B Zone 2 (Hotwell)	Level Gage LG-1900B	Local	-
Condenser 1B Zone 2 (Hotwell)	Level Indication LI-1900	Main Control Board (MCB) Main Control Room	LT-1900
Condenser 1B Zone 2 (Hotwell)	Computer Indication	Computer Computer Room	LT-1900
Condenser 1B Zone 2 (Hotwell)	Computer Indication	Computer Computer Room	TE-1900B
Condenser 1B	Pressure Indication PI-1900 B	Main Control Board (MCB) Main Control Room	PT-1900B
Condenser 1B	Computer Indication	Computer Computer Room	PT-1900B
Condenser 1B Zone 2 Hotwell	High Level Alarm	Annunicator Cabinet 2 ALB-19 Main Control Room	LS-1902
	Low Level Alarm		LS-1901

TABLE 10.4.4-1

STEAM DUMP SYSTEM
DESIGN DATA

Steam Dump System Capacity, lb/hr	5,248,000 (40% of rated full-load steam flow)*
Design Pressure/Temp., Psig/°F	1,185/600
Quantity of steam dump valves	14
Valve Flow Capacity, lowest maximum per valve, lb/hr	652,652**
Type of Valve	Pressure Control Valve
Actuator Type	Pneumatic
No. of Steam Dump valves Discharging to Condenser	6
No. of Steam Dump valves Discharging to Atmosphere	8
Valve Stroke Time (sec):	
Quick Opening (max)	3
Quick Closing (max)	5
Modulating (close)	20

* BASED ON CALCULATED STEAM FLOW AT FULL REACTOR POWER AND 0% SGTP AND TAVG = 588.8°F.

**LOWEST MAXIMUM FLOW VALUE OF THE ENTIRE SET OF DUMP VALVES.

TABLE 10.4.4-2

STEAM DUMP SYSTEM (SDS)
FAILURE MODES AND EFFECTS ANALYSIS

NO.	FAILURE	EFFECT ON SYSTEM	METHOD OF DETECTION	REMARKS
1.	Inadvertent opening or failure to close of a single (SDS) valve during operation	None	Open/shut indication in the Control Room	Isolate atmospheric dump valve and repair. Repair condenser valve dump.
2.	Inadvertent closing of a single (SDS) valve during steam dump operations	None	Open/shut indication in the Control Room	Isolate valve and repair. Remaining valves serve as backup

NOTE: System provides all need functions with one dump valve out of service.

TABLE 10.4.5-1

DESIGN DATA FOR NATURAL DRAFT
HYPERBOLIC COOLING TOWER

a)	Water flow (gpm)	538,007
b)	Temperature of Water entering the tower (F)	121
c)	Temperature of Water Leaving the tower (F)	95.2
d)	Approach (F)	18.2
e)	Design Wet Bulb Temperature (F)	77
f)	Design Relative Humidity (%)	50
g)	Heat Load Handled (10^6 Btu/hr)	6,877
h)	Diameter (ft), at the basin	410
i)	Height (ft), approx	526

TABLE 10.4.5-2

COOLING TOWER MAKEUP PUMP DESIGN PARAMETERS

Quantity	Two: One for Operation, One for Standby
Type	Vertical Mixed Flow
Design Flow (gpm)	26,000
Design Head (ft)	135
Fluid Pumped	Lake Water
Speed (rpm)	885
Brake hp at Design Condition	1034
Pump Efficiency at Design Condition (%)	85
Driver	Electric Motor
Material	Carbon Steel

TABLE 10.4.5-3

CIRCULATING WATER PUMP DESIGN PARAMETERS

Quantity	3
Type	Vertical, Mixed Flow
Design Flow (gpm)	162,533
Design Head (ft)	65.9
Fluid Pumped	Cooling Tower Water
Speed (rpm)	352
Brake hp at Design Condition	3090
Pump Efficiency at Design Condition (%)	88.9
Driver	Electric Motor
Material	Cast Iron

TABLE 10.4.6-2

CIRCULATING COOLING WATER ANALYSIS*

Total Solids	1470 ppm
Suspended solids	300 ppm
Dissolved solids	1170 ppm
Silica as SiO_2	140 ppm
Calcium as Ca	80 ppm
Magnesium as Mg	30 ppm
Sodium as Na	150 ppm
Iron as Fe	14 ppm
Sulfate as SO_4	450 ppm
Chloride as Cl	150 ppm
Nitrate as N	3 ppm
Total Phosphate as P	6.5 ppm
MO Alkalinity as $CaCO_3$	10 ppm
pH.	6.5 - 7.5

*This analysis is for the circulating water upstream of the 10 gpm condenser leak. The values in the table are based on worst case conditions for the lake water and 10 cycles of enrichment for the cooling tower reservoir.

TABLE 10.4.6-3

DESIGN SPECIFICS OF THE CONDENSATE DEMINERALIZER SYSTEM

1) Mixed Bed Vessel	
Quantity	6
When placed in operation	5 in service & 1 standby
Normal flow rate	3,480 gpm per vessel
Peak flow rate	4,840 gpm per vessel
Normal flow	45 gpm/sq. ft.
Peak flow	62 gpm/sq. ft.
Design pressure	300 psig
Operating pressure	250 psig
Operating temperature	126 F
Vessel diameter, minimum	10 ft.
Maximum pressure drop	50 psig
Resin volume per unit	258 cu. ft.
Minimum resin bed depth	3 ft. 0 in.
Lining	Rubber
Code	ASME Section VIII
2) Resin Separation and Cation Regeneration Tank	
Quantity	1
Design pressure	100 psi
Code	ASME Section VIII
Diameter	6 ft. 0 in.
Lining	Rubber
3) Anion Regeneration Vessel	
Quantity	1
Design pressure	100 psi
Code	ASME Section VIII
Diameter	4 ft. 0 in.
Lining	Rubber
Freeboard	100%
4) Resin Storage Vessel	
Quantity	1
Design Pressure	100 psi
Code	ASME Section VIII
Diameter	5 ft. 6 in.
Lining	Rubber
Freeboard	30%
5) Hot Water Tank	
Quantity	1
Design pressure	98 psi
code	ASME
Diameter	7 ft. 0 in.
Lining	Baked Phenolic
Heater	Chromolox

TABLE 10.4.7-1

HEATER DRAIN PUMP DATA

Characteristics	Data
Equipment Numbers	A, B,
Type	Vertical, centrifugal, can type
Pumped fluid	Condensate
Design Temperature, F	380.3
Size of Connections	
Suction	24-inch 300 lb RF Flange
Discharge	16-inch 400 lb RF Flange
Design flow rate, gpm per pump	5100
Design head, ft	875
NPSH required at design flow rate, psi	1.4
Shut off head, ft	1150
Material of Construction	
Casing	ASTM A-217 GR C-5
Impeller	ASTM A-217 GR C-5
Shaft	ASTM A-276 Ty 410
Driver	
Type	Induction motor
Service Factor	1.15
Nameplate rating, hp	1500
Voltage	6600
rpm	1780

TABLE 10.4.7-2

CONDENSATE PUMP DATA

Characteristics	Data
Equipment Numbers	A, B,
Type	Vertical, centrifugal, 3 stage
Pumped fluid	Condensate
Design Temperature, F	126.5
Size of Connections	
Suction	48-inch 150 lb FF Flange
Discharge	24-inch 300 lb RF Flange
Design flow rate, gpm per pump	12,100
Design head, ft	540
NPSH required at design flow rate, ft	18 (at eye of first stage impeller)
Shut off head, ft	665
Material of Construction	
Casing	ASTM-A-283 Gr C
Impellers	Bronze ASTM B-143 alloy 2A or stainless steels A-217 or A-487
Shaft	Stainless steel ASTM A-276 Type 410
Driver	
Type	Induction motor
Service factor	1.15
Nameplate rating, hp	2000
Voltage	6600
rpm, full load	1180

TABLE 10.4.7-3

CONDENSATE BOOSTER PUMP DATA

Characteristics	Data
Equipment Numbers	A, B,
Type	Horizontal, centrifugal single stage
Pumped fluid	Condensate
Design Temperature, F	150
Size of Connections	
Suction	14-inch 300 lb RF Flange
Discharge	12-inch 600 lb RF Flange
Design flow rate, gpm per pump	12,100
Design head, ft.	823
NPSH required at design flow rate, ft.	125
Shut off head, ft.	1100
Material of Construction	
Casing	ASTM A217 Gr CA-15
Impeller	Chrome Steel Alloy A296 Gr CA-6NM
Shaft	Stainless Steel A276 Type 410
Driver	
Type	Induction motor
Service factor	1.15
Nameplate rating, hp	3000
Voltage	6600
rpm	3486

TABLE 10.4.7-4

STEAM GENERATOR FEEDWATER PUMP DATA

Characteristics	Data
Equipment Numbers	A, B,
Type	Horizontal, Centrifugal 2 stages
Pump Fluid	Condensate
Design temperature, F	395
Design flow rate, gpm	15,138*
Size of Connections	
Suction	18-inch buttweld
Discharge	18-inch buttweld
Design head, ft	2123*
NPSH required at design flow rate, ft	180*
Shut off head, ft	3250
Materials of Construction	
Casing	ASTM A226 Class 1
Impeller: first stage second stage	12% chrome casting modified for improved cavitation resistance (modified ASTM A217 grade CA-15)
Shaft	AISI-410 SS Bar with special stress relief.
Driver	
Type	Induction Motor
Service factor	1.15
Nameplate rating, hp	9000 @ design flow rate
Voltage	6600
rpm	3580

*Actual operating values may be different.

TABLE 10.4.8-1

STEAM GENERATOR BLOWDOWN SYSTEMS

1. Flash Tank	
Quantity	1
Type	Vertical
Stored Material	Blowdown Effluent
Design Pressure/temp	170 psi/366 F
Maximum Operating Press/temp	150 psi/366 F
Overall Height	12 ft. 7 in.
Diameter	6 ft. 0 in.
Material of Construction	CS
Code ASME	ASME Section VIII Div. 1
Capacity (Flooded)	1500 gal.
2. Flash Tank Steam Outlet Flow Element	
Type	8" Venturi (Flanged)
Beta Ratio	0.4000
Length	48"
Fluid	Saturated Steam
Design Flow Rate	63,000 lbs/hr
Differential at Design Flow	1170 inches
Design/Operating Pressure	170/150 psig
Design/Operating Temperature	400/366 F
3. Flash Tank Liquid Outlet Flow Element	
Type	6" Venturi (Flanged)
Beta Ratio	0.4204
Length	34"
Fluid	Liquid
Design Flow Rate	222,000 lbs/hr
Differential at Design Flow	159 inches
Design/Operating Pressure	220/150 psig
Design/Operating Temperature	400/345 F
4. Condensate Cooling Water Inlet Line to SGBD Mixing Chamber Flow Element	
Type	2" Nozzle (Flanged)
Beta Ratio	0.4523
Length	13.5"
Fluid	Liquid
Design Flow Rate	25,000 lbs/hr
Differential at Design Flow	100 inches
Design/Operating Pressure	300/270 psig
Design/Operating Temperature	140/126 F

TABLE 10.4.9-1

AUXILIARY FEEDWATER DESIGN PARAMETERS

1) Auxiliary Feedwater Pumps	
Quantity	3
Driver	1 Turbine, 2 Motor
Capacity (gpm each)	900 (turbine driven pump)(1)
	450 (motor driven pumps)(2)
TDH, psig	1265
SG Pressure, psig	1205(3)
Pumping Temperature, °F	32-125
Code	ASME Section III Class 3
Seismic Category	I
2) Piping and Valves	
Code	ASME Section III Class 2 & 3
Seismic Category	I
3) Condensate Storage Tank	
Capacity, gal.	415,000
Minimum TS Capacity, gal.	270,000
Design Pressure	Atmospheric
Code	ASME Section III Class 3
Seismic	I
4) Time to deliver full flow to at least two steam generators upon receipt of an actuation signal without normal offsite and onsite power available (in Sec.)	61.5

NOTES:
(1) Includes 100 gpm recirculation flow.
(2) Includes 50 gpm recirculation.
(3) Lowest safety valve setting plus 3% accumulation.

TABLE 10.4.9-2

FAILURE MODE AND EFFECTS ANALYSIS AUXILIARY FEEDWATER SYSTEM

No.	Name	Failure Mode	Cause	Effects	Method of Detection	Inherent Compensating Provision
1	Motor-driven AFS pump	Fails to start	Diesel Generator fails to start	Loss of flow from this pump	Low pressure indication from AFS pump discharge	Redundant turbine driven AFS pump
2	Turbine-driven AFS pump	Fails to start	DC Power System Failure	Loss of flow from this pump	Low pressure indication from AFS pump discharge	Redundant motor driven AFS pumps
3a	AFS isolation valves	Fails to close to faulted SG	Control failure or loss of power	None	Valve position	Automatic closure of AFS flow control valve
3b	AFS isolation valves	Fails closed to intact SG	Control failure	Temporary loss of flow from corresponding pump	Low flow indication and valve position	Redundant flow provided from other pumps-valve may be manually opened to reestablish flow
4a	AFS flow control valve	Fails to close to Faulted SG	Control failure or loss of power	None	Valve position	Automatic closure of AFS isolation valve
4b	AFS flow control valve	Fails closed to intact SG	Control failure	Temporary loss of flow from corresponding pump	Low flow indication and valve position	Redundant flow provided from other pumps-valve may be manually opened to reestablish flow
5a	AFS pressure control valve	Fails open	Control failure or mechanical binding	Excessive pump runout when system is shutting down causing trip of motor.	Valve position low discharge pressure.	Redundant pumps
5b	AFS pressure control valve	Fails closed	Control failure or mechanical binding	Loss of flow	Valve position high discharge pressure.	Redundant pumps

TABLE 10.4.9-3 AUXILIARY FEEDWATER SYSTEM (AFS)

I. Compliance With Standard Review Plan 10.4.9 Revision 2

Acceptance Criteria	Compliance
Acceptability of the design of the Auxiliary Feedwater System, as described in the applicant's Safety Analysis Report (SAR), is based on specific general design criteria. Listed below are the specific criteria as they relate to the AFS.	
1. General Design Criterion 2, as related to structures housing the system and the system itself being capable of withstanding the effects of earthquakes. Acceptability is based on meeting position C.1 of Regulatory Guide 1.29 for safety-related portions and position C.2 for non-safety related portions.	The Auxiliary Feedwater System (AFS), including instrumentation and controls, are designated Seismic Category I. All components of the AFS except the Condensate Storage Tank (CST), are located within the Reactor Auxiliary Building and the Containment Building which are designated Seismic Category I. The CST is designated Seismic Category I. This meets the requirements of Regulatory Guide 1.29. FSAR Sections: 10.4.9.3, 7.3.1.3.3, 3.1.2
2. General Design Criterion 4, with respect to structures housing the system and the system itself being capable of withstanding the effects of external missiles and internally generated missiles, pipe whip, and jet impingement forces associated with pipe breaks. The basis for acceptance for meeting this criterion is set forth in the SRP Section 3.5 and 3.6 series.	All components of the AFS except the CST, are located within the Reactor Auxiliary Building and the Containment Building which provide protection against the effects of externally generated missiles. A concrete enclosure protects the CST from tornado, hurricane and missile damage. The AFS components are protected against the effects of internally generated missiles by separation and enclosures. The AFS is protected against the dynamic effects associated with high and moderate energy piping failures and has been designed to operate in the environment resulting during normal and accident plant conditions. FSAR Sections 10.4.9.3, 9.2.6.3, 3.1.4, 3.5.1, 3.6.1, 3.6.2, 3.6A and 3.11
3. General Design Criterion 19, as related to the design capability of system instrumentation and controls for prompt hot shutdown of the reactor and potential capability for subsequent cold shutdown. Acceptance is based on meeting BTP RSB 5 1 with regards to Control Room using only safety grade equipment.	The AFS is automatically initiated by an Engineered Safety Features Actuation System (ESFAS) signal as described in Section 7.3. The AFS can also be started manually from the Main Control Room and the auxiliary control panel. Safety related display information provides the operator with sufficient information to perform the required safety functions. FSAR Sections: 10.4.9.5, 7.3.1.3.3, 7.4.1.3 FSAR Tables: 7.4.1-1

TABLE 10.4.9-3 AUXILIARY FEEDWATER SYSTEM (AFS)

I. Compliance With Standard Review Plan 10.4.9 Revision 2	
Acceptance Criteria	Compliance
4. General Design Criterions 34 and 44, to assure:	
a. The capability to transfer heat loads from the reactor system to a heat sink under both normal operating and accident conditions.	The AFS is designed to supply sufficient quantities of feedwater to the secondary side of the steam generators at times when the normal Feedwater System is not available, thereby maintaining the heat sink capabilities of the steam generators. FSAR Sections: 10.4.9, 3.1.30, 3.1.40
b. Redundance of components so that under accident conditions the safety functions can be performed assuming a single active component failure. (This may be coincident with the loss of offsite power for certain events). BTP ASB 10-1 as it relates to AFS pump drive and power supply diversity shall be used in meeting these criterions.	The two motor driven pumps are redundant to the steam turbine driven pump. The motor driven pumps are powered from the redundant emergency buses SA and SB. In the event of loss of the normal power source, power is supplied by the emergency diesel generators associated with these power buses. The turbine steam supply valves are DC motor operated valves powered from redundant vital DC buses. Each pump has separate and independent instrumentation and control circuitry. Per Reference 10.4.9-1, the single active failure is not required to be postulated as occurring coincident with transferring the supply of AFS pump power from off-site to on-site sources. FSAR Sections: 10.4.9.2.3, 7.4.1.3(d) and (e), 7.3.1.3.3
c. The capability to isolate components, subsystems, or piping if required so that the system safety function will be maintained.	The motor driven pumps discharge into a common header which supplies these independent lines, one for each steam generator. Each of these supply lines contain check valves, motor operated isolation valves, and flow control valves. The turbine driven pump supplies three additional lines, one for each steam generator. Each of these supply lines also contains check valves, DC motor operated isolation valves, and AC operated flow control valves powered through the uninterruptable AC instrument panels. This arrangement thus provides the capability to isolate components, subsystems and/or piping if required. FSAR Section: 10.4.9.2.2
5. General Design Criterion 45, as related to design provisions made to permit periodic inservice inspection of system components and equipment.	The AFS is designed to permit periodic inservice inspection. Components are located in accessible locations to facilitate periodic inspection during normal plant operation. The AFS is designed to meet the pump and valve testing requirements. FSAR Sections: 10.4.9.4, 3.1.41, 3.9.6, 6.6

TABLE 10.4.9-3 AUXILIARY FEEDWATER SYSTEM (AFS)

I. Compliance With Standard Review Plan 10.4.9 Revision 2	
Acceptance Criteria	Compliance
6. General Design Criterion 46, as related to design provisions made to permit appropriate functional testing of the system and components to assure structural integrity and leak-tightness, operability and performance of active components, and capability of the integrated system to function as intended during normal, shutdown, and accident conditions. In meeting this criterion the technical specifications should specify that the monthly AFS pump test shall be performed on a staggered test basis to reduce the likelihood of leaving more than one pump in a test mode following the tests.	Design provisions are provided to assure that the AFS can be tested. Each pump is provided with a recirculation line permitting verification of pump operability. Pressure and flow indicators are provided for monitoring system performance. As specified by the Technical Specifications, the AFS pump test will be performed on a staggered test basis to reduce the likelihood of leaving more than one pump in a test mode following the test. FSAR Sections: 10.4.9.4

Table 10.4.9-3 (Continued)

Auxiliary Feedwater System (AFS)
II. Compliance With Branch Technical Position ASB 10-1 Revision 2

Acceptance Criteria	Compliance
1. The auxiliary feedwater system should consist of at least two full-capacity, independent systems that include diverse power sources.	The AFS provides two independent and diverse sources of feedwater, a motor driven train and a turbine driven train. Two motor driven pumps are powered from the ESF electrical AC power distribution system. The turbine steam supply valves are DC motor operated valves powered from the safety related 125 volt DC bus. Clarification of SHNPP's commitments relative to compliance with the diversity criterion is documented in a Nuclear Licensing position related to "Auxiliary Feedwater (AFW) Pump Diversity" dated 11-10-92. FSAR Sections: 10.4.9.2.2, 10.4.9.3, 7.4.1.3, 7.3.1.3.3, 8.3.1, 8.3.2
2. Other powered components of the auxiliary feedwater system should also use the concept of separate and multiple sources of motive energy. An example of the required diversity would be two separate auxiliary feedwater trains, each capable of removing the afterheat load of the reactor system, having one separate train powered from either of the two a-c sources and the other train wholly powered by steam and d-c electric power.	The motor driven train (both pumps, valves, instrumentation and controls) is powered by the ESF electrical AC power distribution system. The turbine driven train is powered by steam and DC buses. The AFS has the capability of supplying 200% of the required flow even with a failure of the largest pump. FSAR Sections: 10.4.9.1, 10.4.9.3
3. The piping arrangement, both intake and discharge, for each train should be designed to permit the pumps to supply feedwater to any combination of steam generators. This arrangement should take into account pipe failure, active component failure, power supply failure, or control system failure that could prevent system function. One arrangement that would be acceptable is crossover piping containing valves that can be operated by remote manual control from the Control Room, using the power diversity principle for the valve operators and actuation systems.	The AFS pumps normally take suction from the condensate storage tank (CST) via a common supply line. In the event of a loss of the CST, the pumps can be remote manually aligned to take suction from the Emergency Service Water System. The motor driven pumps discharge into a common header which supplies three independent lines, one for each steam generator. The turbine driven pump supplies three additional lines, one for each steam generator. Each of the supply lines contains check valves, motor operated isolation valves and flow control valves. A single failure in either train will not effect the other. FSAR Section: 10.4.9.2.2
4. The auxiliary feedwater system should be designed with suitable redundance to offset the consequences of any single active component failure; however, each train need not contain redundant active components.	The AFS is capable of performing its intended safety function despite the single failure of any component. See Table 10.4.9-2 for a summary of the failure mode and effects analysis for the AFS. FSAR Sections: 10.4.9.2.3, 10.4.9.3, 7.4.1.3(d)(e), 7.3.1.3.3

II. Compliance With Branch Technical Position ASB 10-1 Revision 2

Acceptance Criteria	Compliance
5. When considering a high energy line break, the system should be so arranged as to assure the capability to supply necessary emergency feedwater to the steam generators, despite the postulated rupture of any high energy section of the system, assuming a concurrent single active failure.	For a high energy line break (with loss of offsite power) in conjunction with any single active failure, the AFS has adequate capacity to supply the required flow. FSAR Section: 10.4.9.3

TABLE 10.4.9A-1 AFS COMPONENTS LIST

	MANUAL VALVES
VALVE NUMBER	DESCRIPTION
3CE-V27SAB-1	Isolation valve on suction line from Condensate Storage Tank
3CE-V28SA-1	Isolation valve on motor driven pump (MDP) "1A-SA" suction
3CE-V29SB-1	Isolation valve on motor driven pump (MDP) "1B-SB" suction
3CE-V30SAB-1	Isolation valve on turbine driven pump (TDP) "1X-SAB" suction
3AF-V24SA-1	Isolation valve on MDP "1A-SA" mini-flow recirculation line
3AF-V25SB-1	Isolation valve on MDP "1B-SB" mini-flow recirculation line
3AF-V26SAB-1	Isolation valve on TDP "1X-SAB" mini-flow recirculation line
3AF-V5SA-1	Inboard isolation valve on discharge header between MDPs "1A-SA" and "1B-SB"
3AF-V6SA-1	Outboard isolation valve on discharge header between MDPs "1A-SA" and "1B-SB"
3AF-V14SA-1	Inboard isolation valve on discharge header between MDPs "1A-SA" and "1B-SB"
3AF-V15SA-1	Outboard isolation valve on discharge header between MDPs "1A-SA" and "1B-SB"
3AF-V7SA-1	Isolation valve on MDP "1A-SA" discharge header
3AF-V16SA-1	Isolation valve on MDP "1B-SB" discharge header
3AF-V20SA-1	Isolation valve on discharge header between MDPs "1A-SA" and "1B-SB" to steam generator 1C-SN
3AF-V30SB-1	Isolation valve on TDP "1X-SAB" discharge header to steam generator 1A-SN
3AF-V36SB-1	Isolation valve on TDP "1X-SAB" discharge header to steam generator 1B-SN
3AF-V33SB-1	Isolation valve on TDP "1X-SAB" discharge header to steam generator 1C-SN
3MS-V14SAB-1	Isolation valve on TDP "1X-SAB" steam supply line
3AF-V187SA-1	Isolation valve on MDP "1A-SA" mini-flow recirculation line to Condensate Storage Tank
3AF-V188SB-1	Isolation valve on MDP "1B-SB" mini-flow recirculation line to Condensate Storage Tank
	CHECK VALVES
VALVE NUMBER	DESCRIPTION
3CE-V41SA-1	Check valve on MDP "1A-SA" suction
3CE-V42SB-1	Check valve on MDP "1B-SB" suction
3CE-V43SAB-1	Check valve on TDP "1X-SAB" suction
3AF-V27SA-1	Check valve on MDP "1A-SA" mini-flow recirculation line
3AF-V28SB-1	Check valve on MDP "1B-SB" mini-flow recirculation line
3AF-V29SAB-1	Check valve on TDP "1X-SAB" mini-flow recirculation line
3AF-V1SA-1	Check valve on MDP "1A-SA" discharge line
3AF-V2SB-1	Check valve on MDP "1B-SB" discharge line
3AF-V3SAB-1	Check valve on TDP "1X-SAB" discharge line
3AF-V8SA-1	Check valve on MDP "1A-SA" discharge header
3AF-V21SA-1	Check valve on discharge header between MDPs "1A-SA" and "1B-SB" to steam generator 1C-SN
3AF-V17SA-1	Check valve on MDP "1B-SB" discharge header
3AF-V221SA-1	Check valve on MDP "1A-SA" discharge header
3AF-V223SA-1	Check valve on discharge header between MDPs "1A-SA" and "1B-SB" to steam generator 1C-SN

TABLE 10.4.9A-1 AFS COMPONENTS LIST

3AF-V222SA-1	Check valve on MDP "1B-SB" discharge header
3AF-V31SB-1	Check valve on TDP "1X-SAB" discharge header to steam generator 1A-SN
3AF-V37SB-1	Check valve on TDP "1X-SAB" discharge header to steam generator 1B-SN
	CHECK VALVES (continued)
3AF-V34SB-1	Check valve on TDP "1X-SAB" discharge header to steam generator 1C-SN
3AF-V224SB-1	Check valve on TDP "1X-SAB" discharge header to steam generator 1A-SN
3AF-V225SB-1	Check valve on TDP "1X-SAB" discharge header to steam generator 1B-SN
3AF-V226SB-1	Check valve on TDP "1X-SAB" discharge header to steam generator 1C-SN
3MS-V99SA-1	Check valve on TDP "1X-SAB" steam supply line from steam generator 1C-SN
3MS-V100SB-1	Check valve on TDP "1X-SAB" steam supply line from steam generator 1B-SN
2AF-V153SAB-1	Check valve on inlet discharge header to steam generator 1A-SN
2AF-V154SAB-1	Check valve on inlet discharge header to steam generator 1B-SN
2AF-V155SAB-1	Check valve on inlet discharge header to steam generator 1C-SN
	POWER OPERATED VALVES (including control circuits)
VAVLE NUMBER	**DESCRIPTION**
3SW-B75SA-1 (Motor)	Inboard isolation valve on supply line from backup emergency service water system supply header A for MDP "1A-SA"
3SW-B74SA-1 (Motor)	Outboard isolation valve on supply line from backup emergency service water system supply header A for MDP "1A-SA"
3SW-B77SB-1 (Motor)	Inboard isolation valve on supply line from backup emergency service water system supply header B for MDP "1B-SB"
3SW-B76SB-1 (Motor)	Outboard isolation valve on supply line from backup emergency service water system supply header B for MDP "1B-SB"
3SW-B70SA-1 (Motor)	Isolation valve on supply line from backup emergency service water system supply header A for TDP "1X-SAB"
3SW-B71SA-1 (Motor)	Isolation valve on supply line from backup emergency service water system supply header A for TDP "1X-SAB"
3SW-B72SB-1 (Motor)	Isolation valve on supply line from backup emergency service water system supply header B for TDP "1X-SAB"
3SW-B73SB-1 (Motor)	Isolation valve on supply line from backup emergency service water system supply header B for TDP "1X-SAB"
3AF-P1SA-1 (Hydro-motor)	Pressure control valve on MDP "1A-SA" discharge line
3AF-P2SB-1 (Hydro-motor)	Pressure control valve on MDP "1B-SB" discharge line
3AF-F1SA-1 (Hydro-motor)	Flow control valve on MDP "1A-SA" discharge header
3AF-F2SA-1 (Hydro-motor)	Flow control valve on discharge header between MDPs "1A-SA" and "1B-SB" to steam generator 1C-SN
3AF-F3SA-1 (Hydro-motor)	Flow control valve on MDP "1B-SB" discharge line
3AF-F4SB-1 (Hydro-motor)	Flow control valve on TDP "1X-SAB" discharge header to steam generator 1A-SN
3AF-F6SB-1 (Hydro-motor)	Flow control valve on TDP "1X-SAB" discharge header to steam generator 1B-SN
3AF-F5SB-1 (Hydro-motor)	Flow control valve on TDP "1X-SAB" discharge header to steam generator 1C-SN
2AF-V10SB-1 (Motor)	Isolation valve on MDP "1A-SA" discharge header
2AF-V23SB-1 (Motor)	Isolation valve on discharge header between MDP "1A-SA" and "1B-SB" to steam generator 1C-SN
2AF-V19SB-1 (Motor)	Isolation valve on MDP "1B-SB" discharge header
2AF-V116SA-1 (Motor)	Isolation valve on TDP "1X-SAB" discharge header to steam generator 1A-SN
2AF-V117SA-1 (Motor)	Isolation valve on TDP "1X-SAB" discharge header to steam generator 1B-SN
2AF-V118SA-1 (Motor)	Isolation valve on TDP "1X-SAB" discharge header to steam generator 1C-SN
2MS-V8SA-1 (Motor)	Isolation valve on TDP "1X-SAB" steam supply line from steam generator 1B-SN
2MS-V9SB-1 (Motor)	Isolation valve on TDP "1X-SAB" steam supply line from steam generator 1C-SN
TSV (Motor)	TDP "1X-SAB" steam stop valve
TGCV (Electro-Hydraulic)	TDP "1X-SAB" governing control valve

Table 10.4.9A-1 (Continued)

BREAK-DOWN ORIFICE	
ID NUMBER	DESCRIPTION
3AF-U1SA-1	Break-down orifice on MDP "1A-SA" mini-flow recirculation line
3AF-U2SB-1	Break-down orifice on MDP "1B-SB" mini-flow recirculation line
3AF-U3SAB-1	Break-down orifice on TDP "1X-SAB" mini-flow recirculation line

PUMPS	
PUMP	CAPACITY
Motor driven pump (MDP) "1A-SA"	400 gpm + 50 gpm recirculation flow
Motor driven pump (MDP) "1B-SB"	400 gpm + 50 gpm recirculation flow
Turbine driven pump (TDP) "1X-SAB"	800 gpm + 100 gpm recirculation flow

ACTUATING LOGIC	
SIGNAL	PURPOSE
1SGLS-A	Indicates that any SG is in LO-LO level; any SG needs EFW; actuates MDP "A"; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
1SGLS-B	Indicates that any SG is in LO-LO level; any SG needs EFW; actuates MDP "B"; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
SIAS-A	Indicates that safety injection is needed; actuates MDP "A"; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
SIAS-B	Indicates that safety injection is needed; actuates MDP "B"; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
MFWPTS-A	Indicates that both main feedwater pumps are lost; actuates MDP "A"; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
MFWPTS-B	Indicates that both main feedwater pumps are lost; actuates MDP "B"; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
LOOPS-A	Indicates that off-site power is lost; actuates MDP "A"; opens 2MS-V8SA-1; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
LOOPS-B	Indicates that off-site power is lost; actuates MDP "B"; actuates TDP and opens valves 2MS-V9SB-1 and TSV; opens 3AF-F1SA-1, 3AF-F2SA-1, 3AF-F3SA-1
SIS-A	Sequencer initiation signal "A"; actuates MDP "A"
SIS-B	Sequencer initiation signal "B"; actuates MDP "B"
2SGLS-A	Indicates that two out of three SG's are in LO-LO water level; opens valve 2MS-V8SA-1
2SGLS-B	Indicates that two out of three SG's are in LO-LO water level; actuates TDP and opens valves 2MS-V9SB-1 and TSV
SIVOS-A	Indicates that steam isolation valve 2MS-V8SA-1 is open; opens valve 2MS-V9SB-1
TDP trip	Indicates that TDP is in overspeed or in LO-LO suction pressure and TDP speed control is failed; closes TDP stop valve (valve TSV)
TDP speed control	Regulates TDP governing control valve (TGCV) as necessary to maintain pump speed
LBIS-1A-A	Indicates that steam line or feedwater line to SG "A" is ruptured and is in need of line break isolation; closes valves 3AF-FISA-1 and 2AF-V116SA-1
LBIS-1B-A	Indicates that steam line or feedwater line to SG "B" is ruptured and is in need of line break isolation; closes valves 3AF-F3SA-1 and 2AF-V117SA-1
LBIS-1C-A	Indicates that steam line or feedwater line to SG "C" is ruptured and is in need of line break isolation; closes valves 3AF-F2SA-1 and 2AF-V118SA-1
LBIS-1A-B	Indicates that steam line or feedwater line to SG "A" is ruptured and is in need of line break isolation; closes valves 2AF-V10SB-1 and 3AF-F4SB-1
LBIS-1B-B	Indicates that steam line or feedwater line to SG "B" is ruptured and is in need of line break isolation; closes valves 2AF-V19SB-1 and 3AF-F6SB-1
LBIS-1C-B	Indicates that steam line or feedwater line to SG "C" is ruptured and is in need of line break isolation; closes valves 2AF-V23SB-1 and 3AF-F5SB-1
PCAS-A	Tracks MDP "A" discharge pressure; modulates pressure control valve 3AF-P1SA-1
PCAS-B	Tracks MDP "B" discharge pressure; modulates pressure control valve 3AF-P2SB-1
EBUVS-A	Indicates undervoltage at 6.9KV emergency bus 1A-SA
EBUVS-B	Indicates undervoltage at 6.9KV emergency bus 1B-SB

Table 10.4.9A-1 (Continued)

POWER SUPPLIES	
SYSTEM	SERVICED COMPONENTS
6.9 KVAC "A"	MDP "A"
6.9 KVAC "B"	MDP "B"
480 VAC "A"	Valves 3SW-B70SA-1, 3SW-B71SA-1, 3SW-B74SA-1, 3SW-B75SA-1
480 VAC "B"	Valves 2AF-V10SB-1, 2AF-V19SB-1, 2AF-V23SB-1, 3SW-B72SB-1, 3SW-B73SB-1, 3SW-B76SB-1, 3SW B77SB-1
125 VDC "A"	Valves 2MS-V8SA-1, 2AF-V116SA-1, 2AF-V117SA-1, and 2AF-V118SA-1
125 VDC "B"	Valves 2MS-V9SB-1, TSV, and TGCV
120 VAC UPS "A"	Valves 3AF-F1SA-1, 3AF-F2SA-1, and 3AF-F3SA-1
120 VAC UPS "B"	Valves 3AF-F4SB-1, 3AF-F6SB-1, and 3AF-F5SB-1

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
CST FW Supply (Suction) to AFS Pumps							
MIV 3CE-V27SAB-1	--	Open (Locked)	Open	--	--	Loss of CST supply to all three AFW pumps	Operator can make ESWS supply header's "A" and "B" available to all AFW pumps
MIV 3CE-V28SA-1	--	Open (Locked)	Open	--	--	Loss of CST supply to MDP "A"	Backup ESWS sources; Redundant TDP and MDP "B" not affected
MIV 3CE-V29SB-1	--	Open (Locked)	Open	--	--	Loss of CST supply to MDP "B"	Backup ESWS sources: Redundant TDP and MDP "A" not affected
MIV 3CE-V30SAB-1	--	Open (Locked)	Open	--	--	Loss of CST supply to TDP	Backup ESWS sources; Redundant MDP's "A" and "B" not affected
CV 3CE-V41SA-1	--	Closed	Open (Against forward current)	--	--	Loss of CST supply to MDP "A"	Backup ESWS sources; Redundant MDP "B" and TDP not affected
CV 3CE-V42SB-1	--	Closed	Open (Against forward current)	--	--	Loss of CST supply to MDP "B"	Backup ESWS sources; Redundant MDP "A" and TDP not affected
CV 3CE-V43SAB-1	--	Closed	Open (Against forward current)	--	--	Loss of CST supply to TDP	Backup ESWS sources; Redundant MDP "A" and "B" not affected
(Reverse current will not occur under the conditions analyzed)							
ESWS FW Supply (Suction) to AFS Pumps							
MOV 3SW-B70SA-1 (A.C. Motor)	480 VAC "A"	Closed	Open	FAI	Manual	Loss of ESWS supply header "A" as backup source to MDP "B" and TDP; Loss of ESWS supply header "B" as backup source to MDP "A"	CST supply to pumps not affected; ESWS supply header "B" as backup source to MDP "B" and TDP not affected; ESWS supply header "A" as backup source to MDP "A" not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Required On Demand	Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
MOV 3SW-B71SA-1 (A.C. Motor)	480 VAC "A"	Closed	Open	FAI	Manual	Loss of ESWS supply header "A" as backup source to MDP "B" and TDP; Loss of ESWS supply header "B" as backup source to MDP "A"	CST supply to pumps not affected; ESWS supply header "B" as backup source to MDP "B" and TDP not affected; ESWS supply header "A" as backup source to MDP "A" not affected
MOV 3SW-B74SA-1 (A.C. Motor)	480 VAC "A"	Closed	Open	FAI	Manual	Loss of both backup suction sources to MDP "A"	CST supply to MDP "A" not affected. Redundant TDP and MDP "B" not affected
MOV 3SW-B75SA-1 (A.C. Motor)	480 VAC “A”	Closed	Open	FAI	Manual	Same as MOV 3SW-B74SA-1 (above)	Same as MOV 3SW-B74SA-1 (above)
MOV 3SW-B72SB-1 (A.C. Motor)	480 VAC "B"	Closed	Open	FAI	Manual	Loss of ESWS supply header "B" as backup source to MDP "A" and TDP; Loss of ESWS supply header "A" as backup source to MDP "B"	CST supply to pumps not affected; ESWS supply header "A" as backup source to MDP "A" and TDP not affected; ESWS supply header "B" as backup source to MDP "B" not affected
MOV 3SW-B73SB-1 (A.C. Motor)	480 VAC “B”	Closed	Open	FAI	Manual	Same as MOV 3SW-B72SB-1 (above)	Same as MOV 3SW-B72SB-1 (above)
MOV 3SW-B76SB-1 (A.C. Motor)	480 VAC "B"	Closed	Open	FAI	Manual	Loss of both backup suction sources to MDP "B"	CST supply to MDP "B" not affected; Redundant TDP and MDP "A" not affected
MOV 3SW-B77SB-1 (A.C. Motor)	480 VAC “B”	Closed	Open	FAI	Manual	Same as MOV 3SW-B76SB-1 (above)	Same as MOV 3SW-B76SB-1 (above)
Motor Driven Pump “A” Block							
Pump/Motor (A.C. Motor)	6.9 KVAC "A"	Stop	Start	Stop	-Manual -SI actuation -Loss of Offsite Power -Loss of both main FW pumps -Any SG in LO-LO level	Fluid not delivered towards MDP discharge header	Redundant TDP and MDP "B" not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

		Component State					
Component	Power Supplies	Normal (Standby)	Required On Demand	Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
Break-down Orifice (BDO) 3AF-U1SA-1	--	Open	Open	--	--	Loss of MDP "A" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "A" discharge valve is closed (3AF-V1SA-1 or 3AF-P1SA-1)	Redundant TDP and MDP "A" not affected; MDP "A" initial start not affected
SA AC power (6.9 KV)	--	--	Energize pump motor	--	--	Fluid not delivered towards MDP discharge header	Redundant TDP and MDP "B" not affected
ISGLS "A" Logic (ISGLS-A)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
SIAS "A" Logic (SIAS-A)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
MFWPTS "A" Logic (MFWPTS-A)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
LOOPS "A" Logic (LOOPS-A)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
SIS "A" Logic (SIS-A)	--	--	Signal Generated	--	--	Loss of pump auto start	Operator could start pump
CV 3AF-V1SA-1	--	--	Open (Against forward current)	--	--	Loss of delivered FW from MDP "A" to MDP discharge header	Redundant TDP and MDP "B" not affected
	--	--	Close (Against forward current)	--	--	MDP "B" flow partially diverted to mini-flow recirculation MDP "A" loop when MDP "A" discharge pressure lower than MDP "B" discharge header pressure (i.e., MDP “A” is not running)	Redundant TDP and most of MDP "B" flow available
PCV 3AF-P1SA-1 (Piston actuated pressure control valve)	120 VAC "A"	Open	Open	FO	--	Loss of delivered flow from MDP "A" to MDP discharge header	Redundant MDP "B" and TDP not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
			Modulate Closed	FO	Low MDP "A" discharge pressure	Possible pump damage because excessive runout at low SG pressure	Low SG pressure will not occur until several hours into plant cooldown; Redundant MDP "B" and TDP not affected
MIV 3AF-V24SA-1	--	Open	Open	--	--	Loss of MDP "A" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "A" discharge valve is closed (3AF-V1SA-1 or 3AF-P1SA-1)	Redundant TDP and MDP "B" not affected; MDP "A" initial start not affected
CV 3AF-V27SA-1	--	Indet.	Open (Against forward current)	--	--	Loss of MDP "A" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "A" discharge valve is closed (3AF-V1SA-1 or 3AF-P1SA-1)	Redundant TDP and MDP "B" not affected; MDP "A" initial start not affected
		Indet.	Close (Against reverse current)	--	--	TDP and MDP "B" partial mini-flow recirculation through idle MDP "A" loop; no problem	
3AF-V187SA-1		Open	Open			Loss of MDP "A" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "A" discharge valve is closed (3AF-V1SA-1 or 3AF-P1SA-1)	Redundant TDP and MDP "B" not affected; MDP "A" initial start not affected
PCAS-A	--	--	Modulating Signal	--	--	Valve 3AF-P1SA-1 improperly positioned; Loss of MDP "A" flow	Redundant TDP and MDP "B" not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

		Component State					
Component	Power Supplies	Normal (Standby)	Required On Demand	Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
Motor-Driven Pump "B" Block							
Pump/Motor (A.C. Motor)	6.9 KVAC "B"	Stop	Start	Stop	-Manual - SI actuation -Loss of offsite power -Loss of both main FW pumps -Any SG in LO-LO level	Fluid not delivered towards MDP discharge header	Redundant TDP and MDP "A" not affected
Break-Down Orifice (BDO) 3AF-U2SB-1	--	Open	Open	--	--	Loss of MDP "B" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "B" discharge valve is closed (3AF-V2SB-1 or 3AF-P2SB-1)	Redundant TDP and MDP "A" not affected; MDP "B" initial start not affected
SB AC power (6.9KV)	--	--	Energize pump motor	--	--	Fluid not delivered towards MDP discharge header	Redundant TDP and MDP "A" not affected
1 SGLS "B" Logic (1 SGLS-B)	--	--	Signal Generated		--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
SIAS "B" Logic (SIAS-B)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
MFWPTS "B" Logic (MFWPTS-B)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
LOOPS "B" Logic (LOOPS-B)	--	--	Signal Generated	--	--	Loss of one auto start signal to pump	Other auto start signals not affected; Operator could start pump
SIS "B" Logic (SIS-B)	--	--	Signal Generated	--	--	Loss of pump auto start	Operator could start pump
CV 3AF-V2SB-1	--	--	Open (Against forward current)	--	--	Loss of delivered feedwater from MDP "B" to MDP discharge header	Redundant TDP and MDP "A" not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
	--	--	Close (Against forward current)	--	--	MDP "A" flow partially diverted to mini-flow recirculation MDP "B" loop when MDP "B" discharge pressure lower than MDP "A" discharge header pressure (i.e., MDP “B” is not running)	Redundant TDP and most of MDP "A" flow available
PCV 3AF-P2SB-1 (Piston actuated pressure control valve)	120 VAC "B"	Open	Open	FO	--	Loss of delivered flow from MDP "B" to MDP discharge header	Redundant MDP "A" and TDP not affected
			Modulate Closed	FO	Low MDP "B" discharge pressure	Possible pump damage because excessive runout at low SG pressure	Low SG pressure will not occur until several hours into plant cooldown; Redundant MDP "A" and TDP not affected
MIV 3AF-V25SB-1	--	Open	Open	--	--	Loss of MDP "B" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "B" discharge valve is closed (3AF-V2SB-1 or 3AF-P2SB-1)	Redundant TDP and MDP "A" not affected; MDP "B" initial start not affected
CV 3AF-V28SB-1	--	Indet.	Open (Against forward current)	--	--	Loss of MDP "B" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "B" discharge valve is closed (3AF-V2SB-1 or 3AF-P2SB-1)	Redundant TDP and MDP "A" not affected; MDP "B" initial start not affected
	--	Indet.	Close (Against forward current)	--	--	TDP and MDP "A" partial mini-flow recirculation through idle MDP "B" loop; no problem	--

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
3AF-V188SB-1		Open	Open			Loss of MDP "B" mini-flow recirculation; no immediate effect, but possible pump damage if MDP "B" discharge valve is closed (3AF-V2SB-1 or 3AF-P2SB-1)	Redundant TDP and MDP "A" not affected; MDP "B" intial start not affected
PCAS-B	--	--	Modulating Signal	--	--	Valve 3AF P2SB-1 improperly positioned; loss of MDP "B" flow	Redundant TDP and MDP "A" not affected
Turbine Driven Pump Supply							
MOV 2MS-V9SB-1 (D.C. Motor)	125 VDC "B"	Closed	Open	FAI	-2/3 SG Lo-Lo level -Loss of offsite power bus "SB" -Valve 2MS V8SA 1 open signal -Manual	Loss of SG "B" steam supply to TDP	Redundant steam supply from SG "C"
MOV 2MS-V8SA-1 (D.C. Motor)	125 VDC "A"	Closed	Open	FAI	-2/3 SG Lo-Lo level-Loss of offsite power bus "SA" –Manual -Valve 2MS-V9SB-1 open signal	Loss of SG "C" steam supply to TDP	Redundant steam supply from SG "B"
CV 3MS-V99SA-1	--	Indet.	Open (Against forward current)	--	--	Loss of SG "C" steam supply to TDP	Redundant SG “B” steam supply to TDP
		(Reverse current will not occur under the conditions analyzed)					
CV 3MS-V100SB-1	--	Indet.	Open (Against forward current)	--	--	Loss of SG "B" steam supply to TDP	Redundant SG “C” steam supply to TDP
		(Reverse current will not occur under the conditions analyzed)					
MIV 3MS-V14SAB-1	--	Open (Locked)	Open	--	--	Loss of all steam supply to TDP	Redundant MDP's "A" and "B" not affected
MOV, TSV (D.C. Motor)	125 VDC "B"	Open	Open	FAI	-2/3 SG Lo-Lo level -Loss of offsite power bus "SB" -Manual	Loss of all steam supply to TDP	Redundant both MDP’s not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
MOV, TGCV (Piston actuated valve; D.C. Motor)	125 VDC "B"	Open	Open	FO	TDP speed control signal	Loss of all steam supply to TDP	Redundant both MDP's not affected
2SGLS "B" Logic (2SGLS-B)	--	--	Signal Generated	--	--	MOV's 2MS-V9SB-1 and TSV in closed position	SIVOS "A" opens valve 2MS-V9SB-1; redundant steam supply from SG "C"; valve may be manually opened to re-establish steam supply
2SGLS "A" Logic (2SGLS-A)	--	--	Signal Generated	--	--	MOV 2MS-V8SA-1 in closed position	Redundant steam supply from SG "B"; valve may be manually opened to re-establish steam supply
SIVOS "A" Logic (SIVOS-A)	--	--	Signal Generated	--	--	MOV 2MS-V8SA-1 in closed position	Redundant steam supply from SG "C"; valve may be manually opened to re-establish steam supply
LOOPS "A" Logic	--	--	Signal Generated	--	--	MOV 2MS-V8SA-1 in closed position	Redundant steam supply from SG "B"; valve may be manually opened to re-establish steam supply
LOOPS "B" Logic	--	--	Signal Generated	--	--	MOV's 2MS-V9SB-1 and TSV in closed position	SIVOS "A" opens valve 2MS-V9SB-1; redundant steam supply from SG "C"; valve may be manually opened to re-establish steam supply
TDP Trip "B" Logic	--	--	Signal Not Generated	--	--	TDP trip; Loss of delivered FW to TDP discharge header	Redundant MDP's "A" and "B" not affected
TDP Speed Control "B" Logic	--	--	Modulating Signal	--	--	Loss of steam supply to TDP	Redundant MDP's "A" and "B" not affected
Turbine Driven Pump Block							
Pump/Turbine	--	Stop	Start	--	--	Fluid not delivered towards discharge header	Redundant MDP's "A" and "B" not affected
CV 3AF-V3SAB-1	--	Indet.	Open (Against forward current)	--	--	Loss of all delivered FW from TDP to discharge header	Redundant MDP's "A" and "B" not affected

(Reverse current will not occur under the conditions analyzed)

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
MIV 3AF-V26SAB-1	--	Open	Open	--	--	Loss of TDP mini-flow recirculation; no immediate effect, but possible pump damage if TDP discharge valve is closed (3AF-V3SAB-1)	Redundant MDP's "A" and "B"; TDP initial start not affected
CV 3AF-V29SAB-1	--	Indet.	Open (Against forward current)	--	--	Loss of TDP mini-flow recirculation; no immediate effect, but possible pump damage if TDP discharge valve is closed (3AF V3SAB-1)	Redundant MDP's "A" and "B"; TDP initial start not affected
			Closed (Against reverse current)	--	--	MDP's "A" and "B" partial mini-recirculation through idle TDP loop; no problem	
Motor Drive Pump Discharge Header							
MIV 3AF-V5SA-1	--	Open (Locked)	Open	--	--	MDP "A" cannot feed SG's "B" and "C"; MDP "B" cannot feed SG "A"	TDP discharge paths not affected; MDP "A" path to SG "A" not affected; MDP "B" paths to SG's "B" and "C" not affected
MIV 3AF-V6SA-1	--	Open (Locked)	Open	--	--	Same as MIV 3AF-V5SA-1 (above)	Same as MIV 3AF-V5SA-1 (above)
MIV 3AF-V15SA-1	--	Open (Locked)	Open	--	--	MDP "A" cannot feed SG "B"; MDP "B" cannot feed SG's "A" and "C"	TDP paths not affected; MDP "A" paths to SG's "A" and "C" not affected; MDP "B" path to SG "B" not affected
MIV 3AF-V14SA-1	--	Open (Locked)	Open	--	--	Same as MIV 3AF-V15SA-1 (above)	Same as MIV 3AF-V15SA-1 (above)
SG "A" Flow Path From MDP Discharge Header							
MIV 3AF-V7SA-1	--	Open (Locked)	Open	--	--	Loss of all MDP discharge header flow to SG "A"	Redundant TDP can feed SG "A"
FCV 3AF-F1SA-1 (Piston actuated valve; A.C. Motor)	120 VAC "A"	Open	Open	FO	--	Loss of all MDP discharge header flow to SG "A"	Redundant TDP can feed SG "A"

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

		Component State					
Component	Power Supplies	Normal (Standby)	Required On Demand	Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
CV 3AF-V221SA-1	--	Closed	Open (Against forward current)	--	--	Loss of all MDP discharge header flow to SG "A"	Redundant TDP can feed SG "A"
	--		Close (Against reverse current)	--	--	TDP discharge FW diverted to MDP discharge header when MDP discharge header pressure lower than TDP discharge train pressure to SG "A"	Operator can control to solve the problem
CV 3AF-V8SA-1	--	Closed	Open (Against forward current)	--	--	Loss of all MDP discharge header flow to SG "A"	Redundant TDP can feed SG "A"
MOV 2AF-V10SB-1 (A.C. Motor)	480 VAC "B"	Open	Open	FAI	Manual	Loss of delivered FW from both MDP's to SG "A"	Redundant TDP can feed SG "A"; valve may be manually opened to re-establish flow
CV 2AF-V153SAB-1	--	Closed	Open (Against forward current) (Reverse current will not occur under the conditions analyzed)	--	--	Loss of all MDP and TDP delivered FW to SG "A"	SG's "B" and "C" not affected
LBIS-1A-A	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "A"	SG's "B" and "C" not affected
SG "B" Flow Path From MDP Discharge Header							
LBIS-1A-B	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "A"	SG's "B" and "C" not affected
MIV 3AF-V16SA-1	--	Open (Locked)	Open	--	--	Loss of all MDP discharge header flow to SG "B"	Redundant TDP can feed SG "B"
FCV 3AF-F3SA-1 (Piston actuated valve; A.C. Motor)	120 VAC "A"	Open	Open	FO	--	Loss of all MDP discharge header flow to SG "B"	Redundant TDP can feed SG "B"
CV 3AF-V222SA-1	--	Closed	Open (Against forward current)	--	--	Loss of all MDP discharge header flow to SG "B"	Redundant TDP can feed SG "B"

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
	--		Close (Against reverse current)	--	--	TDP discharge FW diverted to MDP discharge header when MDP discharge header pressure lower than TDP discharge train pressure to SG "B"	Operator can control to solve the problem
CV 3AF-V17SA-1	--	Closed	Open (Against forward current)	--	--	Loss of all MDP discharge header flow to SG "B"	Redundant TDP can feed SG "B"
MOV 2AF-V19SB-1 (A.C. Motor)	480 VAC "B"	Open	Open	FAI	Manual	Loss of delivered FW from both MDP's to SG "B"	Redundant TDP can feed SG "B"; valve may be manually opened to re-establish flow
CV 2AF-V154SAB-1	--	Closed	Open (Against forward current) (Reverse current will not occur under the conditions analyzed)	--	--	Loss of all MDP and TDP delivered FW to SG "B"	SG's "A" and "C" not affected
LBIS-1B-A	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "B"	SG's "A" and "C" not affected
LBIS-1B-B	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "B"	SG's "A" and "C" not affected
SG "C" Flow Path From MDP Discharge Header							
MIV 3AF-V20SA-1	--	Open (Locked)	Open	--	--	Loss of all MDP discharge header flow to SG "C"	Redundant TDP can feed SG "C"
FCV 3AF-F2SA-1 (Piston actuated valve; A.C. Motor)	120 VAC "A"	Open	Open	FO	--	Loss of all MDP discharge header flow to SG "C"	Redundant TDP can feed SG "C"
CV 3AF-V223SA-1	--	Closed	Open (Against forward current)	--	--	Loss of all MDP discharge header flow to SG "C"	Redundant TDP can feed SG "C"
	--		Closed (Against reverse current)	--	--	TDP discharge FW diverted to MDP discharge header when MDP discharge header pressure lower than TDP discharge train pressure to SG "C"	Operator can control to solve the problem

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
CV 3AF-V21SA-1	--	Closed	Open (Against forward current)	--	--	Loss of all MDP discharge header flow to SG "C"	Redundant TDP can feed SG "C"
MOV 2AF-V23SB-1 (A.C. Motor)	480 VAC "B"	Open	Open	FAI	Manual	Loss of delivered FW from both MDP's to SG "C"	Redundant TDP can feed SG "C"; valve may be manually opened to re-establish flow
CV 2AF-V155SAB-1	--	Closed	Open (Against forward current) (Reverse current will not occur under the conditions analyzed)	--	--	Loss of all MDP and TDP delivered FW to SG "C"	SG's "A" and "B" not affected
LBIS-1C-A	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "C"	SG's "A" and "B" not affected
LBIS-1C-B	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "C"	SG's "A" and "B" not affected
SG "A" Flow Path From TDP Discharge Header							
MIV 3AF-V30SB-1	--	Open (Locked)	Open	--	--	Loss of all TDP discharge header flow to SG "A"	Redundant MDP's "A" and "B" can feed SG "A"
FCV 3AF-F4SB-1 (Piston Actuated Valve; A.C. Motor)	120 VAC "B"	Open	Open	FO	--	Loss of all TDP discharge header flow to SG "A"	Redundant MDP's "A" and "B" can feed SG "A"
CV 3AF-V224SB-1	--	Closed	Open (Against forward current)	--	--	Loss of all TDP discharge header flow to SG "A"	Redundant MDP's "A" and "B" can feed SG "A"
CV 3AF-V31SB-1	--	Closed	Open (Against forward current)	--	--	Loss of all TDP discharge header flow to SG "A"	Redundant MDP's "A" and "B" can feed SG "A"
MOV 2AF-V116SA-1 (D.C. Motor)	125 VDC "A"	Open	Open	FAI	Manual	Loss of delivered FW from TDP to SG "A"	Redundant MDP's "A" and "B" can feed SG "A"; valve may be manually opened to re-establish flow
CV 2AF-V153SAB-1	--	Closed	Open (Against forward current) (Reverse current will not occur under the conditions analyzed)	--	--	Loss of all MDP and TDP delivered FW to SG "A"	SG's "B" and "C" not affected
LBIS-1A-A	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "A"	SG's "B" and "C" not affected

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

Component	Power Supplies	Component State: Normal (Standby)	Component State: Required On Demand	Component State: Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
LBIS-1A-B	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "A"	SG's "B" and "C" not affected
SG "B" Flow Path From TDP Discharge Header							
MIV 3AF-V36SB-1	--	Open (Locked)	Open	--	--	Loss of all TDP discharge header flow to SG "B"	Redundant MDP's "A" and "B" can feed SG "B"
FCV 3AF-F6SB-1 (Piston Actuated Valve; A.C. Motor)	120 VAC "B"	Open	Open	FO	--	Loss of all TDP discharge header flow to SG "B"	Redundant MDP's "A" and "B" can feed SG "B"
CV 3AF-V225SB-1	--	Closed	Open (Against forward current)	--	--	Loss of all TDP discharge header flow to SG "B"	Redundant MDP's "A" and "B" can feed SG "B"
CV 3AF-V37SB-1	--	Closed	Open (Against forward current)	--	--	Loss of all TDP discharge header flow to SG "B"	Redundant MDP's "A" and "B" can feed SG "B"
MOV 2AF-V117SA-1 (D.C. Motor)	125 VDC "A"	Open	Open	FAI	Manual	Loss of delivered FW from TDP to SG "B"	Redundant MDP's "A" and "B" can feed SG "B"; valve may be manually opened to re-establish flow
CV 2AF-V154SAB-1	--	Closed	Open (Against forward current) (Reverse current will not occur under the conditions analyzed)	--	--	Loss of all MDP and TDP delivered FW to SG "B"	SG's "A" and "C" not affected
LBIS-1B-A	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "B"	SG's "A" and "C" not affected
LBIS-1B-B	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "B"	SG's "A" and "C" not affected
SG "C" Flow Path From TDP Discharge Header							
MIV 3AF-V33SB-1	--	Open (Locked)	Open	--	--	Loss of all TDP discharge header flow to SG "C"	Redundant MDP's "A" and "B" can feed SG "C"
FCV 3AF-F5SB-1 (Piston Actuated Valve; A.C. Motor)	120 VAC "B"	Open	Open	FO	--	Loss of all TDP discharge header flow to SG "C"	Redundant MDP's "A" and "B" can feed SG "C"
CV 3AF-V226SB-1	--	Closed	Open (Against forward current)	--	--	Loss of all TDP discharge header flow to SG "C"	Redundant MDP's "A" and "B" can feed SG "C"

TABLE 10.4.9A-2 AFS FAILURE MODES AND EFFECTS ANALYSIS

		Component State					
Component	Power Supplies	Normal (Standby)	Required On Demand	Failure on Loss of Power	Actuation Signal	Effect of Failure	Inherent Compensation
CV 3AF-V34SB-1	--	Closed	Open (Against forward current)	--	--	Loss of all TDP discharge header flow to SG "C"	Redundant MDP's "A" and "B" can feed SG "C"
MOV 2AF-V118SA-1 (D.C. Motor)	125 VDC "A"	Open	Open	FAI	Manual	Loss of delivered FW from TDP to SG "C"	Redundant MDP's "A" and "B" can feed SG "C"; valve may be manually opened to re-establish flow
CV 2AF-V155SAB-1	--	Closed	Open (Against forward current) (Reverse current will not occur under the conditions analyzed)	--	--	Loss of all MDP and TDP delivered FW to SG "C"	SG's "A" and "B" not affected
LBIS-1C-A	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "C"	SG's "A" and "B" not affected
LBIS-1C-B	--	--	Signal Not Actuated	--	--	Loss of all MDP and TDP delivered FW to SG "C"	SG's "A" and "B" not affected

Table 10.4.9A-2 (Continued)

OVERALL SYSTEM FUNCTION

As noted in Section 10.4.9A.2.1 system minimum function is fulfilled when a total of at least 400 gpm is delivered to at least two steam generators for Case 2 (LMFW and LOOP). This can be accomplished by delivering flow ≥ 134 gpm to all three SG's or by delivering fluid ≥ 200 gpm to any two SG's. DeMorgan's theorem was applied to convert this success criteria to failure criteria, and Absorption theorem was used to reduce the failure criteria to the minimal form, given as follows:

Auxiliary Feedwater System function is not fulfilled if:*

1. < 200 gpm is delivered to SG-A and
   < 134 gpm is delivered to SG-B

   OR

2. < 200 gpm is delivered to SG-A and
   < 134 gpm is delivered to SG-C

   OR

3. < 200 gpm is delivered to SG-B and
   < 134 gpm is delivered to SG-A

   OR

4. < 200 gpm is delivered to SG-B and
   < 134 gpm is delivered to SG-C

   OR

5. < 200 gpm is delivered to SG-C and
   < 134 gpm is delivered to SG-A

   OR

6. < 200 gpm is delivered to SG-C and
   < 134 gpm is delivered to SG-B

* Refer to Table 15.0.3-4 for the latest analysis assumptions on AFW flowrates

TABLE 10.4.9A-3 AFS BASIC EVENT CAUSES AND PROBABILITIES

BASIC EVENT	DESCRIPTION	CAUSE	PROBABILITY ON DEMAND (REF.)
MIV27SABC	Manual Valve 3CE-27SAB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
MIV28SAC	Manual Valve 3CE-V28SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV29SBC	Manual Valve 3CE-V29SB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV30SABC	Manual Valve 3CE-V30SAB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV5SAC	Manual Valve 3AF-V5SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV6SAC	Manual Valve 3AF-V6SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
MIV14SAC	Manual Valve 3AF-V14SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV15SAC	Manual Valve 3AF-V15SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
MIV7SAC	Manual Valve 3AF-V7SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV16SAC	Manual Valve 3AF-V16SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV20SAC	Manual Valve 3AF-V20SA-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV30SBC	Manual Valve 3AF-V30SB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV36SBC	Manual Valve 3AF-V36SB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV33SBC	Manual Valve 3AF-V33SB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MIV14SABC	Manual Valve 3MS-V14SAB-1 Closed/Fails Closed	Plugged	$1x10^{-4}$ (1)
		Human Error (Left Closed)	$5x10^{-3}$ (1)

TABLE 10.4.9A-3 AFS BASIC EVENT CAUSES AND PROBABILITIES

BASIC EVENT	DESCRIPTION	CAUSE	PROBABILITY ON DEMAND (REF.)
		Total	$5.1x10^{-3}$
CV41SAFC	Check Valve 3CE-V41SA-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV42SBFC	Check Valve 3CE-V42SB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV43SABFC	Check Valve 3CE-V43SAB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV1SAFC	Check Valve 3AF-V1SA-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV2SBFC	Check Valve 3AF-V2SB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV3SABFC	Check Valve 3AF-V3SAB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV8SAFC	Check Valve 3AF-V8SA-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV21SAFC	Check Valve 3AF-V21SA-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV17SAFC	Check Valve 3AF-V17SA-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV31SBFC	Check Valve 3AF-V31SB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV37SBFC	Check Valve 3AF-V37SB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV34SBFC	Check Valve 3AF-V34SB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV99SAFC	Check Valve 3MS-V99SA-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV100SBFC	Check Valve 3MS-V100SB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV153SABFC	Check Valve 2AF-V153SAB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV154SABFC	Check Valve 2AF-V154SAB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
CV155SABFC	Check Valve 2AF-V155SAB-1 Fails Closed	Mechanical Binding	$1x10^{-4}$ (1)
MOVB75SAC	Motor Operated Backup ESWS Isolation Valve 3SW-B75SA-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)	$5x10^{-4}$ (1)
		Mechanical Failure	$1x10^{-3}$ (1)
		Plugged	$1x10^{-4}$ (1)
		Control Circuit Failure	$6x10^{-3}$ (1)
		Maintenance Outage	$2.1x10^{-3}$ (2)
		Total	$9.7X10^{-3}$
MOVB74SAC	Motor Operated Backup ESWS Isolation Valve 3SW-B74SA-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)	$5x10^{-4}$ (1)
		Mechanical Failure	$1x10^{-3}$ (1)

TABLE 10.4.9A-3 AFS BASIC EVENT CAUSES AND PROBABILITIES

BASIC EVENT	DESCRIPTION	CAUSE		PROBABILITY ON DEMAND (REF.)
		Plugged		$1x10^{-4}$ (1)
		Control Circuit Failure		$6x10^{-3}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$9.7x10^{-3}$
MOVB70SAC	Motor Operated Backup ESWS Isolation Valve 3SW-B70SA-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)		$5x10^{-4}$ (1)
		Mechanical Failure		$1x10^{-3}$ (1)
		Plugged		$1x10^{-4}$ (1)
		Control Circuit Failure		$6x10^{-3}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$9.7x10^{-3}$
MOVB71SAC	Motor Operated Backup ESWS Isolation Valve 3SW-B71SA-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)		$5x10^{-4}$ (1)
		Mechanical Failure		$1x10^{-3}$ (1)
		Plugged		$1x10^{-4}$ (1)
		Control Circuit Failure		$6x10^{-3}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$9.7x10^{-3}$
MOVB73SBC	Motor Operated Backup ESWS Isolation Valve 3SW-B73SB-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)		$5x10^{-4}$ (1)
		Mechanical Failure		$1x10^{-3}$ (1)
		Plugged		$1x10^{-4}$ (1)
		Control Circuit Failure		$6x10^{-3}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$9.7x10^{-3}$
MOVB76SBC	Motor Operated Backup ESWS Isolation Valve 3SW-B76SB-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)		$5x10^{-4}$ (1)
		Mechanical Failure		$1x10^{-3}$ (1)
		Plugged		$1x10^{-4}$ (1)
		Control Circuit Failure		$6x10^{-3}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$9.7x10^{-3}$
MOVB77SBC	Motor Operated Backup ESWS Isolation Valve 3SW-B77SB-1 Fails to Open	Human Error (CS in MCC-Open Contact Position)		$5x10^{-4}$ (1)
		Mechanical Failure		$1x10^{-3}$ (1)
		Plugged		$1x10^{-4}$ (1)
		Control Circuit Failure		$6x10^{-3}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$9.7x10^{-3}$
PCVP1SAC	Electro-hydraulic Motor Operated Pressure Control Valve 3AF-P1SA-1 Closed	Spurious Auto Close Signal		6.7x10-5 (4)
		Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.3x10^{-3}$
PCVP2SBC	Electro-hydraulic Motor Operated Pressure Control Valve 3AF-P2SB-1 Closed	Spurious Auto Close Signal		$6.7x10^{-5}$ (4)
		Plugged		$1x10^{-4}$ (1)

TABLE 10.4.9A-3 AFS BASIC EVENT CAUSES AND PROBABILITIES

BASIC EVENT	DESCRIPTION	CAUSE		PROBABILITY ON DEMAND (REF.)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.3x10^{-3}$
FCVF1SAC	Electro-hydraulic Motor Operated Flow Control Valve 3AF-F1SA-1 Closed	Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.2x10^{-3}$
FCVF2SAC	Electro-hydraulic Motor Operated Flow Control Valve 3AF-F2SA-1 Closed	Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.2x10^{-3}$
FCVF3SAC	Electro-hydraulic Motor Operated Flow Control Valve 3AF-F3SA-1 Closed	Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.2x10^{-3}$
FCVF4SBC	Electro-hydraulic Motor Operated Flow Control Valve 3AF-F4SB-1 Closed	Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.2x10^{-3}$
FCVF5SBC	Electro-hydraulic Motor Operated Flow Control Valve 3AF-F5SB-1 Closed	Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.2x10^{-3}$
FCVF6SBC	Electro-hydraulic Motor Operated Flow Control Valve 3AF-F6SB-1 Closed	Plugged		$1x10^{-4}$ (1)
		Maintenance Outage		$2.1x10^{-3}$ (2)
			Total	$2.2x10^{-3}$
MOV10SBC	Motor Operated Valve 2AF-V10SB-1 Closed	Human Error (Valve Left Closed)		$5x10^{-4}$ (1)
		Plugged		$1x10^{-4}$ (1)
			Total	$6x10^{-4}$
MOV23SBC	Motor Operated Valve 2AF-V23SB-1 Closed	Human Error (Valve Left Closed)		$5x10^{-4}$ (1)
		Plugged		$1x10^{-4}$ (1)
			Total	$6 x 10^{-4}$
MOV19SBC	Motor Operated Valve 2AF-V19SB-1 Closed	Human Error (Valve Left Closed)		$5x10^{-4}$ (1)
		Plugged		$1x10^{-4}$ (1)
			Total	$6x10^{-4}$
MOV116SAC	Motor Operated Valve 2AF-V116SA-1 Closed	Human Error (Valve Left Closed)		$5x10^{-4}$ (1)
		Plugged		1x10 4 (1)
			Total	$6x10^{-4}$
MOV117SAC	Motor Operated Valve 2AF-V117SA-1 Closed	Human Error (Valve Left Closed)		$5x10^{-4}$ (1)
		Plugged		1x10 4 (1)
			Total	$6 x 10^{-4}$
MOV118SAC	Motor Operated Valve 2AF-V118SA-1 Closed	Human Error (Valve Left Closed)		$5x10^{-4}$ (1)
		Plugged		1x10 4 (1)
			Total	$6x10^{-4}$
MOV8SAC	Motor Operated Valve 2MS-V8SA-1 Fails to Open	Mechanical Failure		$1x10^{-3}$ (1)
		Plugged		$1x10^{-4}$ (1)

TABLE 10.4.9A-3 AFS BASIC EVENT CAUSES AND PROBABILITIES

BASIC EVENT	DESCRIPTION	CAUSE	PROBABILITY ON DEMAND (REF.)
		Steam Isol. Valve 2MS-V9SB-1	
		Open Signal Failure	$2x10^{-3}$ (1)
		Control Circuit Failure	2x10 3 (1)
		Total	$5.1x10^{-3}$
MOV9SBC	Motor Operated Valve 2MS-V9SB-1 Fails to Open	Mechanical Failure	$1x10^{-3}$ (1)
		Plugged	$1x10^{-4}$ (1)
		Control Circuit Failure	2x10 3 (1)
		Total	$3.1x10^{-3}$
TSVSBC	Motor Operated TDP Steam Stop Valve Closed	Plugged	$1x10^{-4}$ (1)
		Spurious Auto Close Signal (Lo-Lo Suction Pressure)	$6.7x10^{-5}$ (4)
		Spurious Auto Close Signal (Pump Overspeed)	$6.7x10^{-5}$ (4)
		Maintenance Outage	$2.1x10^{-3}$ (2)
		Total	$2.3x10^{-3}$
TGCVSBC	Electro-hydraulic Motor Operated TDP Governing Control Valve Closed	Spurious Auto Close Signal (Speed Control System Failure)	$6.7x10^{-5}$ (4)
		Plugged	$1x10^{-4}$ (1)
		Maintenance Outage	$2.1x10^{-3}$ (2)
		Total	$2.3x10^{-3}$
MDPSAF	Motor Driven Pump "A" Fails to Start	Spurious Auto Close Signal (Lo-Lo Suction Pressure)	$1.3x10^{-4}$ (5)
		Mechanical Failure	$1x10^{-3}$ (1)
		Control Circuit Failure	$4x10^{-3}$ (1)
		Total	$5.1x10^{-3}$
MDPSBF	Motor Driven Pump "B" Fails to Start	Spurious Auto Close Signal (Lo-Lo Suction Pressure)	$1.3x10^{-4}$ (5)
		Maintenance Outage	$2.1x10^{-3}$ (2)
		Mechanical Failure	$1x10^{-3}$ (1)
		Control Circuit Failure	$4x10^{-3}$ (1)
		Total	$7.2x10^{-3}$
TDPSABF	Turbine Driven Pump Fails to Start	Mechanical Failure	$1x10^{-3}$ (1)
		Maintenance Outage	$2.1x10^{-3}$ (2)
		Total	
ISGLSAF	Any SG Lo-Lo Level Signal "A" for MDP "A" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
ISGLSBF	Any SG Lo-Lo Level Signal "B" for MDP "B" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
SIASAF	SIAS "A" for MDP "A" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
SIASBF	SIAS "B" for MDP "B" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
MFWPTSAF	Both Main Feedwater Pump Trip Signal "A" for MDP "A" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
MFWPTSBF	Both Main Feedwater Pump Trip Signal	(Not Specified)	$7x10^{-3}$ (1)

TABLE 10.4.9A-3 AFS BASIC EVENT CAUSES AND PROBABILITIES

BASIC EVENT	DESCRIPTION	CAUSE	PROBABILITY ON DEMAND (REF.)
	"B" for MDP "B" Not Generated		
LOOPSAF	LOOP Signal "A" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
LOOPSBF	LOOP Signal "B" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
SISAF	Sequencer Initiation Signal "A" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
SISBF	Sequencer Initiation Signal "B" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
2SGLSAF	2/3 SG's Lo-Lo Level Signal "A" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
2SGLSBF	2/3 SG's Lo-Lo Level Signal "B" Not Generated	(Not Specified)	$7x10^{-3}$ (1)
LBISIAAF	Line Break Isolation Signal "A" for SG-1A Failure	(Not Specified)	$2.3x10^{-4}$ (6)
LBISIABF	Line Break Isolation Signal "B" for SG-1A Failure	(Not Specified)	$2.3x10^{-4}$ (6)
LBISIBAF	Line Break Isolation Signal "A" for SG-1B Failure	(Not Specified)	$2.3x10^{-4}$ (6)
LBISIBBF	Line Break Isolation Signal "B" for SG-1B Failure	(Not Specified)	$2.3x10^{-4}$ (6)
LBISICAF	Line Break Isolation Signal "A" for SG-1C Failure	(Not Specified)	$2.3x10^{-4}$ (6)
LBISICBF	Line Break Isolation Signal "B" for SG-1C Failure	(Not Specified)	$2.3x10^{-4}$ (6)
HE1	Human Error to Backup Automatic AFS Actuation	Operator Error	$5x10^{-4}$ (1)
HE2	Human Error to Actuate Backup Emergency Service Water System During a Post-Accident Nature	Operator Error	$5x10^{-4}$ (1)
6900VACAF	6.9KV AC "A" Power Unavailable - Diesel Generator Fails to Start	DG "A" Fails to Start DG "A" Maint. Outage Total	$3.0x10^{-2}$ (3) $6.4x10^{-3}$ (1) 3.64×10^{-2}
6900VACBF	6.9KV AC "B" Power Unavailable - Diesel Generator Fails to Start	DG "B" Fails to Start DG "B" Maint. Outage Total	$3.0x10^{-2}$ (3) $6.4x10^{-3}$ (1) 3.64x10-2
480VACTAF	480V AC Station Service Transformer "A" Failure	Transformer Fails to Operate	$7.2x10^{-4}$ (3)
480VACTBF	480V AC Station Service Transformer "B" Failure	Transformer Fails to Operate	$7.2x10^{-4}$ (3)
125VDCAF	125V DC "A" Power Supply Fails	(Not Specified)	$2.2x10^{-4}$ (3)
125VDCBF	125V DC "B" Power Supply Fails	(Not Specified)	$2.2x10^{-4}$ (3)
TDPMO	Turbine Driven Pump in Maintenance		$2.1x10^{-3}$ (2)
MDPAMO	Motor Driven Pump "A" in Maintenance		$2.1x10^{-3}$ (2)
MDPBMO	Motor Driven Pump "B" in Maintenance		$2.1x10^{-3}$ (2)

Table 10.4.9A-3 (Continued)

NOTES:

(1) Letter, D. Ross (NRC) to all pending OL Applications of W and CE NSSS Designs, dated March 10, 1980.

(2) Section 10.4.9A.5.1.1

(3) WASH-1400

(4) The probability of the spurious signal generation was derived based on the assumption that the primary cause of spurious signal generation is relay contact shorting and the primary cause of signal failure on demand is failure of relay contacts to actuate. Therefore, spurious signal generation probability is approximated by the probability of signal failure on demand (from Ref. 10.4.9A-1) multiplied by the ratio of relay contact shorting probability (from Ref. 10.4.9A-3) to relay contact failure to actuate probability (from Ref. 10.4.9A-3).

Prob. of Failure on Demand for the Spurious Signal Generated for the MOV = Failure Prob. of the MOV Control Circuit (Monthly Test) (1) x $\frac{Prob.\,of\ Short\ Across\ NO/NC\ Contact\ on\ Relays\ (3)}{Prob.\,of\ Failure\ NO\ Contact\ to\ Close\ on\ Relays\ (3)}$

$$= \frac{(2\times10^{-3})(1\times10^{-8})}{(3\times10^{-7})} = \frac{Prob.\,of\ Short\ Across\ NO/NC\ Contact\ on\ Relays\ (3)}{Prob.\,of\ Failure\ NO\ Contact\ to\ Close\ on\ Relays\ (3)}$$

(5) Prob. of Failure on Demand for the Spurious Signal Generated for the Pump = Failure Prob. of the Pump Control Circuit (Monthly Test) (1) x $\frac{Prob.\,of\ Short\ Across\ NO/NC\ Contact\ on\ Relays\ (3)}{Prob.\,of\ Failure\ NO\ Contact\ to\ Close\ on\ Relays\ (3)}$

$$= \frac{(4\times10^{-3})(1\times10^{-8})}{(3\times10^{-7})} = 1.3\text{x}10^{-4}$$

(6) Prob. of Failure on Demand for the Spurious Line Break Isol. Signal Generated = Failure Prob. of the Actuation Logic (1) x $\frac{Prob.\,of\ Short\ Across\ NO/NC\ Contact\ on\ Relays\ (3)}{Prob.\,of\ Failure\ NO\ Contact\ to\ Close\ on\ Relays\ (3)}$

$$= \frac{(7\times10^{-3})(1\times10^{-8})}{(3\times10^{-7})} = 2.3\ \text{x}10^{-4}$$

TABLE 10.4.9A-4

AFS VALVES SUBJECT TO ASME SECTION XI TESTING

1) Power Operated Valves

   All motor or hydro-motor operated valves in Table 10.4.9A-1.

2) Check Valves

   All check valves except 2AF-V153SAB-1, 2AF-V154SAB-1 and 2AF-V155SAB-1 in Table 10.4.9A-1.

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
Valve - Manual 3CE-V27SAB-1	Monthly (1)	0	-	None	None	None planned or anticipated.
Valve - Manual 3CE-V28SA-1	Monthly (1)	0	-	-	None	MDP "A" maint.; PCV 3AF-P1SA-1 maint.; needs to close valves 3AF-V24SA-1, 3AF-V5SA-1 and 3AF-V7SA-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3CE-V29SB-1	Monthly (1)	0	-	-	None	MDP "B" maint.; PCV 3AF-P2SB-1 maint.; needs to close valves 3AF-V25SB-1, 3AF-V14SA-1 and 3AF-V16SA-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3CE-V30SAB-1	Monthly (1)	0	-	-	None	TDP maint.; valves TGCV and TSV maint.; needs to close valves 3AF-V26SAB-1, 3AF-V30SB-1, 3AF-V36SB-1, 3AF-V33SB-1 and 3MS -V14SAB-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V24SA-1	Monthly(1)	0	-	-	None	MDP "A" maint.; PCV 3AF-P1SA 1 maint.; needs to close valves 3CE-V28SA-1, 3AF-V5SA-1, and 3AF-V7SA 1 needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V25SB-1	Monthly(1)	0	-	-	None	MDP "B" maint.; PCV 3AF-P2SB-1 maint.; needs close valves 3CE-V29SB-1, 3AF-V14SA-1 and 3AF-V16SA-1 needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V26AB-1	Monthly(1)	0	-	-	None	TDP maint., valves TGCV and TSV maint.; needs to close valve 3CE-V30SAB-1, 3AF-V30SB-1, 3AF-V36SB-1, 3AF-V33SB-1,and 3MS-V14SAB-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V5SA-1	Monthly(1)	0	-	-	MDP "A" Test	MDP "A" maint.; PCV 3AF-P1SA-1 maint.; needs to close valves 3CE-V28SA-1, 3AF-V24SA-1, and 3AF-V7SA-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V6SA-1	Monthly(1)	0	-	-	None	Prestart-up feedwater cleaning; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V14SA-1	Monthly(1)	0	-	-	MDP "B" Test	MDP "B" maint.; PCV 3AF-P2SB-1 maint.; needs to close valves 3CE-V29SB-1, and 3AF-V16SA-1; needs

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
						consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V15SA-1	Monthly(1)	0	-	-	None	Prestart-up feedwater cleaning; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V7SA-1	Monthly(1)	0	-	-	MDP "A" Test	MDP "A" maint.; PCV 3AF-P1SA-1 maint.; needs to close valves 3CE-V28SA-1, 3AF-V24SA-1 and 3AF-V5SA-1; FCV 3AF-F1SA-1 maint.; needs to close valve 2AF-V10SB-1; Prestart-up feed water cleaning; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V16SA-1	Monthly(1)	0	-	-	MDP "B" Test	MDP "B" maint.; PCV 3AF-P2SB-1 maint.; needs to close valves 3CE-V29SB-1, 3AF-V25SB-1 and 3AF-V14SA-1; prestart-up feedwater cleaning; FCV 3AF-F3SA-1 maint.; needs to close valve 2AF-V19SB-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V20SA-1	Monthly(1)	0	-	-	None	Prestart-up feedwater cleaning; FCV 3AF-F2SA-1 maint.; needs to close valve 2AF-V23SB-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V20SB-1	Monthly(1)	0	-	-	TDP Test	TDP maint.; valves TGCV and TSV maint.; needs to close valves 3CE-V30SAB-1, 3AF-V26SAB-1, 3AF-V36SB-1, 3AF-V33SB-1, and 3MS-V14SAB-1; FCV 3AF-F4SB-1 maint.; needs to close valve 2AF-V116SA-1; needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V36SB-1	Monthly(1)	0	-	-	TDP Test	TDP maint.; valves TGCV and TSV maint.; needs to close valves 3CE-V30SAB-1, 3AF-V26SAB-1, 3AF-V30SB-1, 3AF-V33SB-1 and 3MS-V14SAB-1; FCV 3AF-F6SB-1 maint.; needs to close valve 2AF V117SA-1 needs consideration for the valve inadvertently left closed.
Valve - Manual 3AF-V33SB-1	Monthly(1)	0	-	-	TDP Test	TDP maint.; valves TGCV and TSV maint.; needs to close valves 3CE-V30SAB-1, 3AF-V26SAB-1, 3AF-V30SB-1, 3AF-V36SB-1, and 3MS-V14SAB-1; FCV 3AF-F5SB-1 maint.; needs to close valve 2AF-V118SA-1; needs consideration for the valve inadvertently left closed.
Valve - Manual	Monthly(1)	0	-	-	None	TDP maint.; valves TGCV and TSV maint.; needs to

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

Component	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
3MS-V14SAB-1						close valves 3CE-V30SAB-1, 3AF-V26SAB-1, 3AF-V30SB-1, 3AF-V36SB-1 and 3AF-V33SB-1; needs consideration for the valve inadvertently left closed.
Valve - Check 3CE-V41SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3CE-V42SB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3CE-V43SAB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V27SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V28SB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V29SAB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V1SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V2SB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V3SAB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V8SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V221SA-1	Quarterly (1	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V21SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V223SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V17SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V222SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V31SB-1	Quarterly(3)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V224SB-1	Quarterly(3)	0	Note 2	-	Not Applicable	Not Applicable

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
Valve - Check 3AF-V37SB-1	Quarterly(3)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V220SB-1	Quarterly(3)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V34SB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3AF-V226SB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3MS-V99SA-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 3MS-V100SB-1	Quarterly(1)	0	Note 2	-	Not Applicable	Not Applicable
Valve - Check 2AF-V153SAB-1	Daily (5)	0	Note 4	-	Not Applicable	Not Applicable
Valve - Check 2AF-V154SAB-1	Daily (5)	0	Note 4	-	Not Applicable	Not Applicable
Valve - Check 2AF-V155SAB-1	Daily (5)	0	Note 4	-	Not Applicable	Not Applicable
Valve - Motor 3SW-B75SA-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B74SA-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B77SB-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B76SB-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B70SA-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B71SA-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B72SB-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve - Motor 3SW-B73SB-1	Quarterly(3)	Note 8	Note 2	$2.1x10^{-3}$	None	-
Valve-HydroMotor 3AF-P1SA-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	-
Valve-HydroMotor	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	-

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
3AF-P2SB-1						
Valve-HydroMotor 3AF-F1SA-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None
Valve-HydroMotor 3AF-F2SA-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None
Valve-HydroMotor 3AF-F3SA-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None
Valve-HydroMotor 3AF-F4SB-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None
Valve-HydroMotor 3AF-F6SB-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None
Valve-HydroMotor 3AF-F5SB-1	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None
Valve - Motor 2AF-V10SB-1	Quarterly(3)	Notes 7&8	Note 4	0	LBIS "B" test for SG "A"; needs consideration for inadvertently left closed	None
Valve - Motor 2AF-V23SB-1	Quarterly(3)	Notes 7&8	Note 4	0	LBIS "B" test for SG "C"; needs consideration for inadvertently left closed	None
Valve - Motor 2AF-V19SB-1	Quarterly(3)	Notes 7&8	Note 4	0	LBIS "B" test for SG "B"; needs consideration for inadvertently left closed	None
Valve - Motor 2AF-V116SA-1	Quarterly(3)	Notes 7&8	Note 4	0	LBIS "A" test for SG "A"; needs consideration for inadvertently left closed	None
Valve - Motor 2AF-V117SA-1	Quarterly(3)	Notes 7&8	Note 4	0	LBIS "A" test for SG "B"; needs consideration for inadvertently left closed	None
Valve - Motor 2AF-V118SA-1	Quarterly(3)	Notes 7&8	Note 4	0	LBIS "A" test for SG "C"; needs consideration for inadvertently left closed	None
Valve - Motor 2MS-V8SB-1	Quarterly(3)	Notes 8	Note 4	0	None	-
Valve - Motor 2MS-V9SA-1	Quarterly(3)	Notes 8	Note 4	0	None	-
Valve - Motor TSV	Quarterly(6)	Notes 8	Note 2	$2.1x10^{-3}$	None	-
Valve-Hydromotor	Quarterly(6)	0	Note 2	$2.1x10^{-3}$	None	None

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
TGCV						
MDP "A"	Quarterly	0	Note 2	$2.1x10^{-3}$	None	None
MDP "B"	Quarterly	0	Note 2	$2.1x10^{-3}$	None	None
TDP	Quarterly	0	Note 2	$2.1x10^{-3}$	None	None
EFAS MDP "A" Logic	Quarterly and once per 18 months (9)	0	Note 2	-	None	None
EFAS MDP "B" Logic	Quarterly and once per 18 months (9)	0	Note 2	-	None	None
EFAS TDP "B" Logic	Quarterly and once per 18 months (9)	0	Note 2	-	None	None
EGAS TDP "A" Logic	Quarterly and once per 18 months (9)	0	Note 2	-	None	None
TDP Overspeed Trip	Quarterly	0	Note 2	-	None	None
TDP Speed Control	Quarterly	0	Note 2	-	None	None
Pressure Control Valve Closing Signal "A"	Quarterly	0	Note 2	-	None	None
Pressure Control Valve Closing Signal "B"	Quarterly	0	Note 2	-	None	None
Line Break Isolation Signal (LBIS) in MDP Discharge Header for SG "A", Logic "A"	Once per 18 months	0	Note 2	-	None	None
LBIS in MDP Discharge Header for SG "B", Logic	Once per 18 months	0	Note 2	-	None	None

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
"A"						
LBIS in MDP Discharge Header for SG "C", Logic "A"	Once per 18 months	0	Note 2	-	None	None
LBIS in MDP Discharge Header for SG "A", Logic "B"	Once per 18 months	0	Note 2	-	None	None
LBIS in MDP Discharge Header for SG "B", Logic "B"	Once per 18 months	0	Note 2	-	None	None
LBIS in MDP Discharge Header for SG "C", Logic "B"	Once per 18 months	0	Note 2	-	None	None
LBIS in TDP Discharge Header for SG "A", Logic "A"	Once per 18 months	0	Note 2	-	None	None
LBIS in TDP Discharge Header for SG "B", Logic "A"	Once per 18 months	0	Note 2	-	None	None
LBIS in TDP Discharge Header for SG "C", Logic "A"	Once per 18 months	0	Note 2	-	None	None
LBIS in TDP Discharge Header for SG "A", Logic "B"	Once per 18 months	0	Note 2	-	None	None
LBIS in TDP Discharge Header for SG "B", Logic "B"	Once per 18 months	0	Note 2	-	None	None

TABLE 10.4.9A-5 SUMMARY OF TEST AND MAINTENANCE CONTRIBUTIONS TO AFS COMPONENTS AVAILABILITY

	Testing of Component		Maintenance on Component		Other Tests Involving Components Which Contribute to Unavailability	Other Maintenance Acts Involving Components Which Contribute to Unavailability
Component	Frequency	Unavailability From Test	Frequency	Unavailability From Maint.		
LBIS in TDP Discharge Header for SG "C", Logic "B"	Once per 18 months	0	Note 2	-	None	None
6.9KV AC Power "A" (DG "A")	Monthly	0	Note 2	$6.4x10^{-3}$	None	None
6.9KV AC Power "B" (DG "B")	Monthly	0	Note 2	$6.4x10^{-3}$	None	None
125V DC Power "A" (Battery "A")	Monthly	0	Note 2	-	None	None
125V DC Power "B" (Battery "B")	Monthly	0	Note 2	-	None	None

Table 10.4.9A-5 (Continued)

NOTES:

(1) Non-automatic (manual) valves are inspected and verified for their correct positions monthly.

(2) Components are maintained during power operation only if results of periodic tests are unsatisfactory.

(3) Quarterly valve tests are required by ASME Section XI.

(4) Valve cannot be maintained during power operation due to connection with pressurized system.

(5) During normal operation the check valves are available for continuous operation to transfer fluids from main feedwater system.

(6) Each automatic valve in the flow path is verified for the fully open position during quarterly feedwater pump tests.

(7) If a valve is left closed after a test, then water cannot be transferred to its corresponding SG.

(8) If a contact of control switch in MCC is in open position after a quarterly test, then steam supply from its related valve cannot be provided.

(9) Partial logic from the manual control switch "open" to a pump motor is tested during the quarterly pump test and then following each automatic signal is simulated once per 18 months to start an AFW pump during shutdown:

a. For motor driven pumps,

1) Steam generator water level low-low or

2) Safety injection.

b. For turbine driven pumps,

1) Steam generator water level low-low (2 steam generators).

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
1	3	MIV14SABC	MDPSAF	MDPSBF	$2.6x\ 10^{-7}$	3.9
2	3	MIV14SAC	MIV14SABC	MDPSAF	$1.9x10^{-7}$	2.9
3	3	MIV5SAC	MIV14SABC	MDPSBF	$1.9x10^{-7}$	2.9
4	3	MDPSAF	MDPSBF	TDPSABF	$1.6x10^{-7}$	2.4
5	3	MIV16SAC	MIV20SAC	MIV14SABC	$1.3x10^{-7}$	2.0
6	3	MIV7SAC	MIV16SAC	MIV14SABC	$1.3x10^{-7}$	2.0
7	3	MIV7SAC	MIV20SAC	MIV14SABC	$1.3x10^{-7}$	2.0
8	3	TGCVSBC	MDPSAF	MDPSBF	$1.2x10^{-7}$	1.8
9	3	TSVSBC	MDPSAF	MDPSBF	$1.2x10^{-7}$	1.8
10	3	MIV14SAC	MDPSAF	TDPSABF	$1.1x10^{-7}$	1.7
11	3	MIV5SAC	MDPSBF	TDPSABF	$1.1x10^{-7}$	1.7
12	3	MIV14SAC	TGCVSBC	MDPSAF	$8.4x\ 10^{-8}$	1.3
13	3	MIV5SAC	TGCVSBC	MDPSBF	$8.4x10^{-8}$	1.3
14	3	MIV14SAC	TSVSBC	MDPSAF	$8.4x10^{-8}$	1.3
15	3	MIV5SAC	TSVSBC	MDPSBF	$8.4x10^{-8}$	1.3
16	3	MIV14SABC	PCVP1SAC	MDPSBF	$8.4x10^{-8}$	1.3
17	3	MIV14SABC	PCVP2SBC	MDPSAF	$8.4x10^{-8}$	1.3
18	3	MIV16SAC	MIV20SAC	TDPSABF	$8.1x10^{-8}$	1.2
19	3	MIV7SAC	MIV16SAC	TDPSABF	$8.1x10^{-8}$	1.2
20	3	MIV7SAC	MIV20SAC	TDPSABF	$8.1x10^{-8}$	1.2

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)						
TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100\ (\%)$
21	3	MIV16SAC	MIV20SAC	TGCVSBC	$6.0x10^{-8}$	0.9
22	3	MIV7SAC	MIV16SAC	TGCVSBC	$6.0x10^{-8}$	0.9
23	3	MIV7SAC	MIV20SAC	TGCVSBC	$6.0x10^{-8}$	0.9
24	3	MIV16SAC	MIV20SAC	TSVSBC	$6.0x10^{-8}$	0.9
25	3	MIV7SAC	MIV16SAC	TSVSBC	$6.0x10^{-8}$	0.9
26	3	MIV7SAC	MIV20SAC	TSVSBC	$6.0x10^{-8}$	0.9
27	3	MIV14SAC	MIV14SABC	PCVP1SAC	$6.0x10^{-8}$	0.9
28	3	MIV5SAC	MIV14SABC	PCVP2SBC	$6.0x10^{-8}$	0.9
29	3	MIV20SAC	MIV14SABC	FCVF3SAC	$5.7x10^{-8}$	0.9
30	3	MIV7SAC	MIV14SABC	FCVF3SAC	$5.7x10^{-8}$	0.9
31	3	MIV16SAC	MIV14SABC	FCVF2SAC	$5.7x10^{-8}$	0.9
32	3	MIV16SAC	MIV14SABC	FCVF1SAC	$5.7x10^{-8}$	0.9
33	3	MIV7SAC	MIV14SABC	FCVF2SAC	$5.7x10^{-8}$	0.9
34	3	MIV20SAC	MIV14SABC	FCVF1SAC	$5.7x10^{-8}$	0.9
35	2	LBIS1AAF	LBIS1CBF		$5.3x10^{-8}$	0.8
36	2	LBIS1ABF	LBIS1CAF		$5.3x10^{-8}$	0.8
37	2	LBIS1AAF	LBIS1BAF		$5.3x10^{-8}$	0.8
38	2	LBIS1BAF	LBIS1CAF		$5.3x10^{-8}$	0.8
39	2	LBIS1AAF	LBIS1BBF		$5.3x10^{-8}$	0.8
40	2	LBIS1ABF	LBIS1BAF		$5.3x10^{-8}$	0.8
41	2	LBIS1BBF	LBIS1CAF		$5.3x10^{-8}$	0.8
42	2	LBIS1ABF	LBIS1BBF		$5.3x10^{-8}$	0.8

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)						
TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100\ (\%)$
43	2	LBIS1BAF	LBIS1CBF		5.3x10^{-8}	0.8
44	2	LBIS1BBF	LBIS1CBF		5.3x10^{-8}	0.8
45	2	LBIS1AAF	LBIS1CAF		5.3x10^{-8}	0.8
46	2	LBIS1ABF	LBIS1CBF		5.3x10^{-8}	0.8
47	3	PCVP1SAC	MDPSBF	TDPSABF	5.1x10^{-8}	0.8
48	3	PCVP2SBC	MDPSAF	TDPSABF	5.1x10^{-8}	0.8
49	2	MIV27SABC	HE2		5.0x10^{-8}	0.8
50	3	PCVP1SAC	TGCVSBC	MDPSBF	3.8x10^{-8}	0.6
51	3	PCVP2SBC	TGCVSBC	MDPSAF	3.8x10^{-8}	0.6
52	3	PCVP1SAC	TSVSBC	MDPSBF	3.8x10^{-8}	0.6
53	3	PCVP2SBC	TSVSBC	MDPSAF	3.8x10^{-8}	0.6
54	3	MIV5SAC	PCVP2SBC	TDPSABF	3.6x10^{-8}	0.5
55	3	MIV14SAC	PCVP1SAC	TDPSABF	3.6x10^{-8}	0.5
56	3	MIV20SAC	FCVF3SAC	TDPSABF	3.5x10^{-8}	0.5
57	3	MIV7SAC	FCVF3SAC	TDPSABF	3.5x10^{-8}	0.5
58	3	MIV16SAC	FCVF2SAC	TDPSABF	3.5x10^{-8}	0.5
59	3	MIV16SAC	FCVF1SAC	TDPSABF	3.5x10^{-8}	0.5
60	3	MIV7SAC	FCVF2SAC	TDPSABF	3.5x10^{-8}	0.5
61	3	MIV20SAC	FCVF1SAC	TDPSABF	3.5x10^{-8}	0.5
62	3	MIV14SAC	PCVP1SAC	TGCVSBC	2.7x10^{-8}	0.4
63	3	MIV5SAC	PCVP2SBC	TGCVSBC	2.7x10^{-8}	0.4
64	3	MIV14SAC	PCVP1SAC	TSVSBC	2.7x10^{-8}	0.4

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100\ (\%)$
65	3	MIV5SAC	PCVP2SBC	TSVSBC	2.7×10^{-8}	0.4
66	3	MIV14SABC	PCVP1SAC	PCVP2SBC	2.7×10^{-8}	0.4
67	3	MIV20SAC	FCVF3SAC	TGCVSBC	2.6×10^{-8}	0.4
68	3	MIV7SAC	FCVF3SAC	TGCVSBC	2.6×10^{-8}	0.4
69	3	MIV16SAC	FCVF2SAC	TGCVSBC	2.6×10^{-8}	0.4
70	3	MIV16SAC	FCVF1SAC	TGCVSBC	2.6×10^{-8}	0.4
71	3	MIV7SAC	FCVF2SAC	TGCVSBC	2.6×10^{-8}	0.4
72	3	MIV20SAC	FCVF1SAC	TGCVSBC	2.6×10^{-8}	0.4
73	3	MIV20SAC	FCVF3SAC	TSVSBC	2.6×10^{-8}	0.4
74	3	MIV7SAC	FCVF3SAC	TSVSBC	2.6×10^{-8}	0.4
75	3	MIV16SAC	FCVF2SAC	TSVSBC	2.6×10^{-8}	0.4
76	3	MIV16SAC	FCVF1SAC	TSVSBC	2.6×10^{-8}	0.4
77	3	MIV7SAC	FCVF2SAC	TSVSBC	2.6×10^{-8}	0.4
78	3	MIV20SAC	FCVF1SAC	TSVSBC	2.6×10^{-8}	0.4
79	3	MIV14SABC	FCVF2SAC	FCVF3SAC	2.5×10^{-8}	0.4
80	3	MIV14SABC	FCVF1SAC	FCVF3SAC	2.5×10^{-8}	0.4
81	3	MIV14SABC	FCVF1SAC	FCVF2SAC	2.5×10^{-8}	0.4
82	2	CV154SABFC	LBIS1CAF		2.3×10^{-8}	0.3
83	2	CV153SABFC	LBIS1CAF		2.3×10^{-8}	0.3
84	2	CV154SABFC	LBIS1AAF		2.3×10^{-8}	0.3
85	2	CV155SABFC	LBIS1BAF		2.3×10^{-8}	0.3
86	2	CV155SABFC	LBIS1BBF		2.3×10^{-8}	0.3

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
87	2	CV154SABFC	LBIS1ABF		2.3x10^{-8}	0.3
88	2	CV153SABFC	LBIS1BAF		2.3x10^{-8}	0.3
89	2	CV153SABFC	LBIS1BBF		2.3x10^{-8}	0.3
90	2	CV155SABFC	LBIS1AAF		2.3x10^{-8}	0.3
91	2	CV155SABFC	LBIS1ABF		2.3x10^{-8}	0.3
92	2	CV154SABFC	LBIS1CBF		2.3x10^{-8}	0.3
93	2	CV153SABFC	LBIS1CBF		2.3x10^{-8}	0.3
94	3	PCVP1SAC	PCVP2SBC	TDPSABF	1.6x10^{-8}	0.2
95	3	MIV20SAC	MIV14SABC	MOV19SBC	1.6x10^{-8}	0.2
96	3	MIV7SAC	MIV14SABC	MOV19SBC	1.6x10^{-8}	0.2
97	3	MIV16SAC	MIV14SABC	MOV23SBC	1.6x10^{-8}	0.2
98	3	MIV16SAC	MIV14SABC	MOV10SBC	1.6x10^{-8}	0.2
99	3	MIV7SAC	MIV14SABC	MOV23SBC	1.6x10^{-8}	0.2
100	3	MIV20SAC	MIV14SABC	MOV10SBC	1.6x10^{-8}	0.2
101	3	FCVF1SAC	FCVF2SAC	TDPSABF	1.5x10^{-8}	0.2
102	3	FCVF2SAC	FCVF3SAC	TDPSABF	1.5x10^{-8}	0.2
103	3	FCVF1SAC	FCVF3SAC	TDPSABF	1.5x10^{-8}	0.2
104	3	PCVP1SAC	PCVP2SBC	TGCVSBC	1.2x10^{-8}	0.2
105	3	PCVP1SAC	PCVP2SBC	TSVSBC	1.2x10^{-8}	0.2
106	3	FCVF2SAC	FCVF3SAC	TGCVSBC	1.1x10^{-8}	0.2
107	3	FCVF1SAC	FCVF3SAC	TGCVSBC	1.1x10^{-8}	0.2
108	3	FCVF1SAC	FCVF2SAC	TGCVSBC	1.1x10^{-8}	0.2

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100\ (\%)$
109	3	FCVF2SAC	FCVF3SAC	TSVSBC	1.1×10^{-8}	0.2
110	3	FCVF1SAC	FCVF3SAC	TSVSBC	1.1×10^{-8}	0.2
111	3	FCVF1SAC	FCVF2SAC	TSVSBC	1.1×10^{-8}	0.2
112	2	CV154SABFC	CV155SABFC		1.0×10^{-8}	0.2
113	2	CV153SABFC	CV155SABFC		1.0×10^{-8}	0.2
114	2	CV153SABFC	CV154SABFC		1.0×10^{-8}	0.2
115	3	MIV7SAC	MOV23SBC	TDPSABF	9.5×10^{-9}	0.1
116	3	MIV16SAC	MOV10SBC	TDPSABF	9.5×10^{-9}	0.1
117	3	MIV20SAC	MOV10SBC	TDPSABF	9.5×10^{-9}	0.1
118	3	MIV7SAC	MOV19SBC	TDPSABF	9.5×10^{-9}	0.1
119	3	MIV20SAC	MOV19SBC	TDPSABF	9.5×10^{-9}	0.1
120	3	MIV16SAC	MOV23SBC	TDPSABF	9.5×10^{-9}	0.1
121	3	MIV27SABC	MOVB71SAC	MOVB73SBC	9.4×10^{-9}	0.1
122	3	MIV27SABC	MOVB71SAC	MOVB72SBC	9.4×10^{-9}	0.1
123	3	MIV27SABC	MOVB70SAC	MOVB73SBC	9.4×10^{-9}	0.1
124	3	MIV27SABC	MOVB70SAC	MOVB72SBC	9.4×10^{-9}	0.1
125	3	MIV20SAC	MOV19SBC	TGCVSBC	7.0×10^{-9}	0.1
126	3	MIV7SAC	MOV19SBC	TGCVSBC	7.0×10^{-9}	0.1
127	3	MIV16SAC	MOV23SBC	TGCVSBC	7.0×10^{-9}	0.1
128	3	MIV16SAC	MOV10SBC	TGCVSBC	7.0×10^{-9}	0.1
129	3	MIV7SAC	MOV23SBC	TGCVSBC	7.0×10^{-9}	0.1
130	3	MIV20SAC	MOV10SBC	TGCVSBC	7.0×10^{-9}	0.1

TABLE 10.4.9A-6 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY – CASE 1 (LMFW)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
131	3	MIV20SAC	MOV19SBC	TSVSBC	7.0x10^{-9}	0.1
132	3	MIV7SAC	MOV19SBC	TSVSBC	7.0x10^{-9}	0.1
133	3	MIV16SAC	MOV23SBC	TSVSBC	7.0x10^{-9}	0.1
134	3	MIV16SAC	MOV10SBC	TSVSBC	7.0x10^{-9}	0.1
135	3	MIV7SAC	MOV23SBC	TSVSBC	7.0x10^{-9}	0.1
136	3	MIV20SAC	MOV10SBC	TSVSBC	7.0x10^{-9}	0.1
137	3	MIV14SABC	FCVF2SAC	MOV19SBC	6.7x10^{-9}	0.1
138	3	MIV14SABC	FCVF1SAC	MOV19SBC	6.7x10^{-9}	0.1
139	3	MIV14SABC	FCVF3SAC	MOV23SBC	6.7x10^{-9}	0.1
140	3	MIV14SABC	FCVF3SAC	MOV10SBC	6.7x10^{-9}	0.1
141	3	MIV14SABC	FCVF1SAC	MOV23SBC	6.7x10^{-9}	0.1
142	3	MIV14SABC	FCVF2SAC	MOV10SBC	6.7x10^{-9}	0.1

TABLE 10.4.9A-7 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY - CASE 2 (LMFW/LOOP)						
TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
1	2	6900VACAF	125VDCBF		8.0×10^{-6}	13.1
2	3	MIV14SABC	6900VACAF	6900VACBF	6.8×10^{-6}	11.1
3	3	MIV30SABC	6900VACAF	6900VACBF	6.8×10^{-6}	11.1
4	3	TDPSABF	6900VACAF	6900VACBF	4.1×10^{-6}	6.7
5	3	TGCVSBC	6900VACAF	6900VACBF	3.0×10^{-6}	4.9
6	3	TSVSBC	9600VACAF	6900VACBF	3.0×10^{-6}	4.9
7	2	MDPSAF	125VDCBF		1.6×10^{-6}	2.6
8	3	MIV14SABC	MDPSAF	6900VACBF	1.3×10^{-6}	2.1
9	3	MIV14SABC	MDPSBF	6900VACAF	1.3×10^{-6}	2.1
10	2	MIV5SAC	125VDCBF		1.1×10^{-6}	1.8
11	3	MIV14SAC	MIV14SABC	6900VACAF	9.5×10^{-7}	1.6
12	3	MIV29SBC	MIV14SABC	6900VACAF	9.5×10^{-7}	1.6
13	3	MIV28SAC	MIV14SABC	6900VACBF	9.5×10^{-7}	1.6
14	3	MIV5SAC	MIV14SABC	6900VACBF	9.5×10^{-7}	1.6
15	3	MDPSAF	TDPSABF	6900VACBF	8.1×10^{-7}	1.3
16	3	MDPSBF	TDPSABF	6900VACAF	8.1×10^{-7}	1.3
17	3	TGCVSBC	MDPSAF	6900VACBF	6.0×10^{-7}	1.0
18	3	TGCVSBC	MDPSBF	6900VACAF	6.0×10^{-7}	1.0

TABLE 10.4.9A-7 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY - CASE 2 (LMFW/LOOP)						
TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{a}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
19	3	TSVSBC	MDPSAF	6900VACBF	$6.0x10^{-7}$	1.0
20	3	TSVSBC	MDPSBF	6900VACAF	$6.0x10^{-7}$	1.0
21	3	MIV14SAC	TDPSABF	6900VACAF	$5.8x10^{-7}$	1.0
22	3	MIV29SBC	TDPSABF	6900VACAF	$5.8x10^{-7}$	1.0
23	3	MIV28SAC	TDPSABF	6900VACBF	$5.8x10^{-7}$	1.0
24	3	MIV5SAC	TDPSABF	6900VACBF	$5.8x10^{-7}$	1.0
25	2	PCVP1SAC	125VDCBF		$5.0x10^{-7}$	0.8
26	3	MIV14SAC	TGCVSBC	6900VACAF	$4.3x10^{-7}$	0.7
27	3	MIV29SBC	TGCVSBC	6900VACAF	$4.3x10^{-7}$	0.7
28	3	MIV28SAC	TGCVSBC	6900VACBF	$4.3x10^{-7}$	0.7
29	3	MIV5SAC	TGCVSBC	6900VACBF	$4.3x10^{-7}$	0.7
30	3	MIV14SAC	TSVSBC	6900VACAF	$4.3x10^{-7}$	0.7
31	3	MIV29SBC	TSVSBC	6900VACAF	$4.3x10^{-7}$	0.7
32	3	MIV28SAC	TSVSBC	6900VACBF	$4.3x10^{-7}$	0.7
33	3	MIV5SAC	TSVSBC	6900VACBF	$4.3x10^{-7}$	0.7
34	3	MIV14SABC	PCVP1SAC	6900VACBF	$4.3x10^{-7}$	0.7
35	3	MIV14SABC	PCVP2SBC	6900VACAF	$4.3x10^{-7}$	0.7
36	3	MIV14SABC	MDPSAF	MDPSBF	$2.6x10^{-7}$	0.4
37	3	PCVP1SAC	TDPSABF	6900VACBF	$2.6x10^{-7}$	0.4

TABLE 10.4.9A-7 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY - CASE 2 (LMFW/LOOP)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{a}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
38	3	PCVP2SBC	TDPSABF	6900VACAF	$2.6x10^{-7}$	0.4
39	3	PCVP1SAC	TGCVSBC	6900VACBF	$1.9x10^{-7}$	0.3
40	3	PCVP2SBC	TGCVSBC	6900VACAF	$1.9x10^{-7}$	0.3
41	3	PCVP1SAC	TSVSBC	6900VACBF	$1.9x10^{-7}$	0.3
42	3	PCVP2SBC	TSVSBC	6900VACAF	$1.9x10^{-7}$	0.3
43	3	MIV14SAC	MIV14SABC	MDPSAF	$1.9x10^{-7}$	0.3
44	3	MIV5SAC	MIV14SABC	MDPSBF	$1.9x10^{-7}$	0.3
45	3	MDPSAF	MDPSBF	TDPSABF	$1.6x10^{-7}$	0.3
46	3	MIV16SAC	MIV20SAC	MIV14SABC	$1.3x10^{-7}$	0.2
47	3	MIV7SAC	MIV16SAC	MIV14SABC	$1.3x10^{-7}$	0.2
48	3	MIV7SAC	MIV20SAC	MIV14SABC	$1.3x10^{-7}$	0.2
49	3	CV3SABFC	6900VACAF	6900VACBF	$1.3x10^{-7}$	0.2
50	3	CV43SABFC	6900VACAF	6900VACBF	$1.3x10^{-7}$	0.2
51	3	MIV27SABC	6900VACAF	6900VACBF	$1.3x10^{-7}$	0.2
52	3	TGCVSBC	MDPSAF	MDPSBF	$1.2x10^{-7}$	0.2
53	3	TSVSBC	MDPSAF	MDPSBF	$1.2x10^{-7}$	0.2
54	3	MIV5SAC	MDPSBF	TDPSABF	$1.1x10^{-7}$	0.2
55	3	MIV14SAC	MDPSAF	TDPSABF	$1.1x10^{-7}$	0.2
56	3	MIV14SAC	TGCVSBC	MDPSAF	$8.4x10^{-8}$	0.1

TABLE 10.4.9A-7 DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY - CASE 2 (LMFW/LOOP)						
TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{a}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
57	3	MIV5SAC	TGCVSBC	MDPSBF	$8.4x10^{-8}$	0.1
58	3	MIV14SAC	TSVSBC	MDPSAF	$8.4x10^{-8}$	0.1
59	3	MIV5SAC	TSVSBC	MDPSBF	$8.4x10^{-8}$	0.1
60	3	MIV14SABC	PCVP1SAC	MDPSBF	$8.4x10^{-8}$	0.1
61	3	MIV14SABC	PCVP2SBC	MDPSAF	$8.4x10^{-8}$	0.1
62	3	MIV16SAC	MIV20SAC	TDPSABF	$8.1x10^{-8}$	0.1
63	3	MIV7SAC	MIV16SAC	TDPSABF	$8.1x10^{-8}$	0.1
64	3	MIV7SAC	MIV20SAC	TDPSABF	$8.1x10^{-8}$	0.1

TABLE 10.4.9A-8

DOMINANT MINIMAL CUTSETS SORTED BY PROBABILITY - CASE 3 (LMFW/SB)

TERM NO.	NUMBER OF ORDER	MINIMAL CUTSET			PROBABILITY OF TERM ($\bar{\bar{a}}_i$)	$\frac{\bar{a}_i}{\bar{a}} \times 100$ (%)
1	1	MIV14SABC			5.1×10^{-3}	26.8
2	1	MIV30SABC			5.1×10^{-3}	26.8
3	1	TDPSABF			3.1×10^{-3}	16.3
4	1	TSVSBC			2.3×10^{-3}	12.1
5	1	TGCVSBC			2.3×10^{-3}	12.1
6	1	125VDCBF			2.2×10^{-4}	1.2
7	1	CV43SABFC			1.0×10^{-4}	0.5
8	1	MIV27SABC			1.0×10^{-4}	0.5
9	1	CV3SABFC			1.0×10^{-4}	0.5
10	2	MIV36SBC	MIV33SBC		2.6×10^{-5}	0.1
11	2	MIV30SBC	MIV33SBC		2.6×10^{-5}	0.1
12	2	MIV30SBC	MIV36SBC		2.6×10^{-5}	0.1

TABLE 10.4.9A-9 <u>BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 1 (LMFW)</u>

FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER		
		ALL	ORDER 2	ORDER 3
MIV14SABC	$2.1x10^{-6}$	145	0	145
MDPSAF	$1.4x10^{-6}$	25	0	25
MDPSBF	$1.4x10^{-6}$	25	0	25
TDPSABF	$1.3x10^{-6}$	145	0	145
MIV20SAC	$1.2x10^{-6}$	94	0	94
MIV16SAC	$1.2x10^{-6}$	94	0	94
MIV7SAC	$1.2x10^{-6}$	94	0	94
TGCVSBC	$9.5x10^{-7}$	145	0	145
TSVSBC	$9.5x10^{-7}$	145	0	145
MIV14SAC	$6.3x10^{-7}$	15	0	15
MIV5SAC	$6.3x10^{-7}$	15	0	15
FCVF2SAC	$5.1x10^{-7}$	94	0	94
FCVF3SAC	$5.1x10^{-7}$	94	0	94
FCVF1SAC	$5.1x10^{-7}$	94	0	94
PCVP1SAC	$4.4x10^{-7}$	25	0	25
PCVP2SBC	$4.4x10^{-7}$	25	0	25
LBIS1ABF	$3.3x10^{-7}$	78	6	72
LBIS1AAF	$3.3x10^{-7}$	78	6	72
LBIS1BBF	$3.3x10^{-7}$	78	6	72
LBIS1BAF	$3.3x10^{-7}$	78	6	72
LBIS1CAF	$3.3x10^{-7}$	78	6	72
LBIS1CBF	$3.3x10^{-7}$	78	6	72
CV153SABFC	$1.5x10^{-7}$	78	6	72
CV154SABFC	$1.5x10^{-7}$	78	6	72
CV155SABFC	$1.5x10^{-7}$	78	6	72
MOV23SBC	$1.4x10^{-7}$	94	0	94
MOV19SBC	$1.4x10^{-7}$	94	0	94
MOV10SBC	$1.4x10^{-7}$	94	0	94
MIV27SABC	$1.4x10^{-7}$	25	1	24
HE2	$5.0x10^{-8}$	1	1	0
MIV30SBC	$4.6x10^{-8}$	24	0	24

TABLE 10.4.9A-9 BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 1 (LMFW)

FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER		
		ALL	ORDER 2	ORDER 3
MIV36SBC	$4.6x10^{-8}$	24	0	24
MIV33SBC	$4.6x10^{-8}$	24	0	24
CV3SABFC	$4.1x10^{-8}$	145	0	145
MOVB70SAC	$3.1x10^{-8}$	7	0	7
MOVB71SAC	$3.1x10^{-8}$	7	0	7
MOVB72SBC	$3.1x10^{-8}$	7	0	7
MOVB73SBC	$3.1x10^{-8}$	7	0	7
CV21SAFC	$2.3x10^{-8}$	94	0	94
CV17SAFC	$2.3x10^{-8}$	94	0	94
CV8SAFC	$2.3x10^{-8}$	94	0	94
FCVF4SBC	$2.0x10^{-8}$	24	0	24
FCVF6SBC	$2.0x10^{-8}$	24	0	24
FCVF5SBC	$2.0x10^{-8}$	24	0	24
CV1SAFC	$1.9x10^{-8}$	25	0	25
CV2SBFC	$1.9x10^{-8}$	25	0	25
MIV15SAC	$1.2x10^{-8}$	15	0	15
MIV6SAC	$1.2x10^{-8}$	15	0	15
MOV116SAC	$5.4x10^{-9}$	24	0	24
MOV117SAC	$5.4x10^{-9}$	24	0	24
MOV118SAC	$5.4x10^{-9}$	24	0	24
CV31SBFC	$9.0x10^{-10}$	24	0	24
CV37SBFC	$9.0x10^{-10}$	24	0	24
CV34SBFC	$9.0x10^{-10}$	24	0	24

*Importance is taken as the Fussell-Vesely measure. See Section 10.4.9A.6.1 for details.

TABLE 10.4.9A-10 BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 2 (LMFW/LOOP)

FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER		
		ALL	ORDER 2	ORDER 3
6900VACAF	$4.2x10^{-5}$	52	1	51
6900VACBF	$3.4x10^{-5}$	61	0	61
MIV14SABC	$1.6x10^{-5}$	170	0	170
125VDCBF	$1.1x10^{-5}$	185	7	178
TDPSABF	$1.0x10^{-5}$	170	0	170
TSVSBC	$7.4x10^{-6}$	170	0	170
TGCVSBC	$7.4x10^{-6}$	170	0	170
MIV30SABC	$6.8x10^{-6}$	1	0	1
MDPSAF	$6.3x10^{-6}$	31	1	30
MDPSBF	$4.8x10^{-6}$	37	0	37
MIV5SAC	$4.1x10^{-6}$	21	1	20
MIV14SAC	$3.1x10^{-6}$	41	0	41
MIV28SAC	$2.5x10^{-6}$	15	0	15
MIV29SBC	$2.4x10^{-6}$	5	0	5
PCVP1SAC	$2.0x10^{-6}$	31	1	30
PCVP2SBC	$1.5x10^{-6}$	37	0	37
MIV20SAC	$1.2x10^{-6}$	110	0	110
MIV7SAC	$1.2x10^{-6}$	110	0	110
MIV16SAC	$1.2x10^{-6}$	108	0	108
MIV27SABC	$5.2x10^{-7}$	66	1	65
FCVF2SAC	$5.2x10^{-7}$	110	0	110
FCVF1SAC	$5.2x10^{-7}$	110	0	110
FCVF3SAC	$5.1x10^{-7}$	108	0	108
LBIS1CBF	$3.4x10^{-7}$	88	6	82
LBIS1ABF	$3.4x10^{-7}$	88	6	82
LBIS1AAF	$3.4x10^{-7}$	88	6	82
LBIS1CAF	$3.4x10^{-7}$	88	6	82
LBIS1BAF	$3.4x10^{-7}$	86	6	80
LBIS1BBF	$3.4x10^{-7}$	86	6	80
CV3SABFC	$3.2x10^{-7}$	170	0	170
125VDCAF	$2.5x10^{-7}$	43	1	42

TABLE 10.4.9A-10 BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 2 (LMFW/LOOP)

FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER		
		ALL	ORDER 2	ORDER 3
CV153SABFC	$1.5x10^{-7}$	88	6	82
CV155SABFC	$1.5x10^{-7}$	88	6	82
CV154SABFC	$1.5x10^{-7}$	86	6	80
MOV23SBC	$1.4x10^{-7}$	110	0	110
MOV10SBC	$1.4x10^{-7}$	110	0	110
MOV19SBC	$1.4x10^{-7}$	108	0	108
CV43SABFC	$1.3x10^{-7}$	1	0	1
CV1SAFC	$8.8x10^{-8}$	31	1	30
MIV6SAC	$8.1x10^{-8}$	21	1	20
MOVB73SBC	$7.9x10^{-8}$	12	0	12
MOVB70SAC	$7.9x10^{-8}$	12	0	12
MOVB71SAC	$7.9x10^{-8}$	12	0	12
MOVB72SBC	$7.9x10^{-8}$	12	0	12
CV2SBFC	$6.6x10^{-8}$	37	0	37
MIV15SAC	$6.0x10^{-8}$	41	0	41
MOV8SBC	$5.7x10^{-8}$	6	0	6
HE2	$5.1x10^{-8}$	3	1	2
CV41SAFC	$4.9x10^{-8}$	15	0	15
CV42SBFC	$4.7x10^{-8}$	5	0	5
MIV30SBC	$4.6x10^{-8}$	24	0	24
MIV36SBC	$4.6x10^{-8}$	24	0	24
MIV33SBC	$4.6x10^{-8}$	24	0	24
CV21SAFC	$2.3x10^{-8}$	110	0	110
CV8SAFC	$2.3x10^{-8}$	110	0	110
CV17SAFC	$2.3x10^{-8}$	108	0	108
FCVF5SBC	$2.0x10^{-8}$	24	0	24
FCVF4SBC	$2.0x10^{-8}$	24	0	24
FCVF6SBC	$2.0x10^{-8}$	24	0	24
MOVB75SAC	$1.1x10^{-8}$	3	0	3
MOVB74SAC	$1.1x10^{-8}$	3	0	3
480VACTAF	$5.8x10^{-9}$	12	0	12
480VACTBF	$5.8x10^{-9}$	12	0	12
MOV117SAC	$5.4x10^{-9}$	24	0	24

TABLE 10.4.9A-10 BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 2 (LMFW/LOOP)

FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER		
		ALL	ORDER 2	ORDER 3
MOV118SAC	$5.4x10^{-9}$	24	0	24
MOV116SAC	$5.4x10^{-9}$	24	0	24
CV100SBFC	$1.1x10^{-9}$	6	0	6
CV37SBFC	$9.0x10^{-10}$	24	0	24
CV34SBFC	$9.0x10^{-10}$	24	0	24
CV31SBFC	$9.0x10^{-10}$	24	0	24
SISAF	$7.7x10^{-10}$	1	0	1
HE1	$7.7x10^{-10}$	1	0	1

*Importance is taken as the Fussell-Vesely measure. See Section 10.4.9A.6.1 for details.

TABLE 10.4.9A-11 BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 2 (LMFW/SB)

FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER			
		ALL	ORDER 1	ORDER 2	ORDER 3
MIV30SABC	$5.1x10^{-3}$	1	1	0	0
MIV14SABC	$5.1x10^{-3}$	1	1	0	0
TDPSABF	$3.1x10^{-3}$	1	1	0	0
TGCVSBC	$2.3x10^{-3}$	1	1	0	0
TSVSBC	$2.3x10^{-3}$	1	1	0	0
125VDCBF	$2.2x10^{-4}$	1	1	0	0
CV43SABFC	$1.0x10^{-4}$	1	1	0	0
CV3SABFC	$1.0x10^{-4}$	1	1	0	0
MIV27SABC	$1.0x10^{-4}$	1	1	0	0
MIV33SBC	$8.7x10^{-5}$	14	0	14	0
MIV30SBC	$8.7x10^{-5}$	14	0	14	0
MIV36SBC	$8.7x10^{-5}$	14	0	14	0
FCVF5SBC	$3.8x10^{-5}$	14	0	14	0
FCVF4SBC	$3.8x10^{-5}$	14	0	14	0
FCVF6SBC	$3.8x10^{-5}$	14	0	14	0
MOV8SBC	$1.7x10^{-5}$	3	0	3	0
MOV9SAC	$1.6x10^{-5}$	2	0	2	0
MOV118SAC	$1.0x10^{-5}$	14	0	14	0
MOV116SAC	$1.0x10^{-5}$	14	0	14	0
MOV117SAC	$1.0x10^{-5}$	14	0	14	0
LBIS1CAF	$3.9x10^{-6}$	14	0	14	0
LBIS1CBF	$3.9x10^{-6}$	14	0	14	0
LBIS1BBF	$3.9x10^{-6}$	14	0	14	0
LBIS1BAF	$3.9x10^{-6}$	14	0	14	0
LBIS1ABF	$3.9x10^{-6}$	14	0	14	0
LBIS1AAF	$3.9x10^{-6}$	14	0	14	0
CV155SABFC	$1.7x10^{-6}$	14	0	14	0
CV34SBFC	$1.7x10^{-6}$	14	0	14	0
CV153SABFC	$1.7x10^{-6}$	14	0	14	0

TABLE 10.4.9A-11 BASIC FAILURE EVENTS SORTED ACCORDING TO IMPORTANCE* - CASE 2 (LMFW/SB)					
FAILURE EVENT	F-V IMPORTANCE MEASURES*	NO. OF OCCURRENCES IN EACH ORDER			
		ALL	ORDER 1	ORDER 2	ORDER 3
CV154SABFC	$1.7x10^{-6}$	14	0	14	0
CV37SBFC	$1.7x10^{-6}$	14	0	14	0
CV31SBFC	$1.7x10^{-6}$	14	0	14	0
125VDCAF	$1.1x10^{-6}$	2	0	2	0
CV99SAFC	$5.2x10^{-7}$	2	0	2	0
CV100SBFC	$3.4x10^{-7}$	3	0	3	0
2SGLSBF	$2.5x10^{-8}$	1	0	0	1
LOOPSBF	$2.5x10^{-8}$	1	0	0	1
HE1	$2.5x10^{-8}$	1	0	0	1

*Importance is taken as the Fussel-Vesely measure. See Section 10.4.9A.6.1 for details.

TABLE 10.4.9B-1

CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN BASIS CONDITIONS

CONDITION OR TRANSIENT(2)	CLASSIFICATION	CRITERIA*	ADDITIONAL DESIGN CRITERIA
Loss of main feedwater	Condition II	Peak RCS pressure not to exceed design pressure. No adverse effects on the core.	No water released through the pressurizer power-operated relief valves or safety valves.
Station Blackout	Condition II	Same as LMFW.	Same as LMFW.
Steamline Rupture	Condition IV	DNB design basis is met assuming most reactive RCCA stuck in fully withdrawn position. 10 CFR 50.67 dose limits not exceeded.	
Feedline Rupture	Condition IV	RCS design pressure not exceeded. 10 CFR 50.67 dose limits not exceeded.	Core does not uncover.
Loss of all AC Power	N/A	Note 1	Same as blackout assuming turbine driven pump operation
Loss of Coolant	Condition III	10 CFR 50.67 Dose Limits 10 CFR 50.46 Limits	
	Condition IV	(Same as for Condition III)	
Cooldown	N/A		100F/Hr. 556F to 350F

* Ref: ANSI N18.2 (This information provided for those transients performed in the FSAR).

Note 1: Although this transient establishes the basis for auxiliary feedwater pump powered by a diverse power source, this is not evaluated relative to typical criteria since multiple failures must be assumed to postulate this transient.

Note 2: Refer to Section 6.3.3.5 and 15.6.3 for a discussion of AFW operation during a SGTR.

TABLE 10.4.9B-2 SUMMARY OF ASSUMPTIONS USED IN AFS DESIGN VERIFICATION ANALYSES

	Transient*****	Loss of Feedwater (Station Blackout)	Cooldown	Main Feedline Break	Main Steamline Break (containment)
a.	Max reactor power	102% of ESD rating (102% of 2910 MWt)	2910 MWt	102% of ESD rating (102% of 2910 MWt)	0, 30, 70, 102% of rated (percent of 2785 MWt)
b.	Time delay from event to Rx trip	50.0 sec**	2 sec**	23.0 sec**	Variable.
c.	AFS actuation signal/time delay for AFW flow	Low Low SG level 61.5 seconds****	N/A	Low Low SG level/61.5 seconds****	Assumed immediately.
d.	SG water level at time of reactor trip	Low Low SG level	N/A	Low Low SG level	N/A
e.	Initial SG inventory	116,193 lbm/SG	106,000 lbm/SG	100,197 lbm/SG (Faulted) 89,937 lbm/SG (Intact)	0% - 163000 lbm/SG 30% - 150000 lbm/SG 70% - 133000 lbm/SG 102% - 120000 lbm/SG
	Rate of change before and after AFS actuation	See Attached Figure 1	N/A	See Attached Figure 2	N/A
	Decay heat	ANSI/ANS 5.1-1979 + 2 Std. Dev.	ANS + 20%	ANSI/ANS 5.1-1979 +2 Std. Dev.	ANS + 2-%
f.	AFW pump design pressure	1236 psia	1236 psia	1236 psia	N/A
g.	Minimum # of SGs which must receive AFW flow	2 of 3	N/A	2 of 3	N/A
h.	RC pump status	Tripped at reactor trip	One pump operating	All operating	All operating
i.	Maximum AFW temperature	120F	120F	120F	Equal to main FW temperature
j.	Operator action	none	N/A	None - Automatic AFW Isolation at 266 + 41 = 307 sec.	None - Automatic AFW Isolation at 200 sec.
k.	AFW purge volume/and temperature	30 ft3 per SG/at FW temperature	None	30 ft^3 per SG/at FW temperature	None
l.	Normal blowdown	none assumed	none assumed	none assumed	none assumed

m.	Sensible heat	see cooldown*	Table 10.4.9B-3	see cooldown*	N/A
n.	Time at standby/time to cooldown to RHR	see cooldown	2 hrs./4 hrs.	see cooldown	N/A
o.	AFW flow rate	430 gpm	variable	430 gpm***	1500 gpm

* No thick metal heat transfer assumed.

** Two seconds delay time assumed from Reactor Trip Signal to Rod Motion.

*** 286 gpm is assumed prior to AFW isolation; 430 gpm assumed after isolation.

**** The analysis includes an additional 1.5 seconds delay (60 + 1.5 seconds) after reaching the steam generator low low level trip condition before actuation of the protective function.

***** Refer to Section 15.6.3 and Table 15.0.3-4 for a discussion of AFW operation and the current analysis flowrate assumptions for the SGTR event.

TABLE 10.4.9B-3

SUMMARY OF SENSIBLE HEAT SOURCES

Primary water sources (initially at engineered safeguards design power temperature and inventory)

- RCS fluid
- Pressurizer fluid (liquid and vapor)

Primary metal sources (initially at engineered safeguards design power temperature)

- Reactor coolant piping, pumps, and reactor vessel
- Pressurizer
- Steam generator tube metal and tube sheet
- Steam generator metal below tube sheet
- Reactor vessel internals

Secondary water sources (initially at engineered safeguards design power temperature and inventory)

- Steam generator fluid (liquid and vapor)

Secondary metal sources (initially at engineered safeguards design power temperature)

- All steam generator metal above tube sheet, excluding tubes

TABLE 10.4.9B-4 AFS COMPLIANCE WITH NRC SHORT AND LONG TERM RECOMMENDATIONS

Recommendation	Compliance
GS-1 Technical Specification Time Limit on AFW System Train Outage	The Technical Specifications in Chapter 16.0 of the FSAR (page 3/4 7-3) proposes a specification which is consistent with this recommendation.
GS-2 Technical Specification Administrative Controls on Manual Valves - Lock and Verify Position	The Technical Specifications in Chapter 16.0 of the FSAR (page 3/4 7-4) proposes a specification which is consistent with this recommendation.
GS-3 AFW Flow Throttling -Water Hammer	The AFS is designed to supply sufficient quantities of feedwater to the secondary side of the steam generators to achieve stable hot standby conditions and plant cooldown if necessary. FSAR Section 10.4.9.3 discusses the steps taken to preclude water hammer in the AFS. SHNPP does not utilize throttling as a means to avoid water hammer. Water hammer in the AFS is minimized by designing the system to remain full of water. The suction piping to the AFW pumps and part of the discharge piping are always under a positive head of water due to the higher elevation of the CST. The discharge piping from the steam generator nozzle to the first check valve is pressurized to steam generator pressure. Feedwater system pressure; CST static head pressure and leakage across pumps and valving will maintain a water solid system on the AFW pump discharge side. Frequent system testing and inspections will ensure the AFS is full of water. Void formation in the vicinity of the steam generator auxiliary feed nozzle during power operation is prevented by the tempering flow from the Feedwater System (Section 10.4.7). In addition, the AFS will be monitored for water hammer during the initial test program as described in Section 3.9.2.1.
GS-4 Emergency Procedures for Initiating Backup Water Supplies	1) Operator action is not required to line up the AFW primary water supply. An adequate primary water supply is reserved and available upon demand from the seismic Category 1 safety grade system. See Section 10.4.9.2 for a discussion on the automatic initiation of AFS. Safety grade indication and alarms are provided for AFW pump low suction pressure along with control switches for valve operation for the alternate water supply (ESW). 2) Operating Procedures for the AFS include the case where the AFS suction must be aligned to the emergency service water system. These procedures will identify the steps necessary to assure that the AFS is operable following the transfer. See compliance statement for Item GL 3.
GS-5 Emergency Procedures for Initiating AFW Flow Following a Complete Loss of Alternating Current Power	Procedures for manual local action are not required.

TABLE 10.4.9B-4 AFS COMPLIANCE WITH NRC SHORT AND LONG TERM RECOMMENDATIONS

Recommendation	Compliance
GS-6 AFS Flow Path Verification	1) Operating and Maintenance procedures will require the operator to determine proper alignment of AFW System valves. As described in response to NUREG-0737 Item I.C.6(5), a second, qualified individual will verify that the AFW System is properly aligned when returned to service following periodic testing or maintenance. 2)Surveillance requirements for the AFW system are described in the Technical Specifications. Acceptability of the Technical Specifications are determined by the NRC.
GS-7 Non-Safety Grade, Non-Redundant AFS Automatic Initiation Signals	See compliance statement for GL-5.
GS-8 Automatic Initiation of AFS	See compliance statement for GL-5.
GS-9 Primary AFW Water Source Low Level Alarm	Level indication and alarms are provided as described in FSAR Section 9.2.6 and shown on Figure 10.1.0-4 to provide indication of CST water level with alarms to include an empty alarm for operator action in transferring to an alternate water supply (ESW).
GS-10 AFW Pump Endurance Test	A 48-hour endurance test will be conducted.
GS-11 Indication of AFW Flow to the Steam Generators	1) Class 1E flow instruments are provided to indicate flow to each steam generator. Flow indication is provided in the Main Control Room. See Section 7.5.1.3.5. 2) The AFW flow instrument channels are powered from their associated safety grade emergency buses as discussed in Section 7.9.
GS-12 AFS Availability During Periodic Surveillance Testing	The SHNPP AFW system design includes three independent trains: two utilize independent electric motor driven pumps and one utilizes a steam turbine driven pump. Refer to FSAR Section 10.4.9 for further discussion of this design. Surveillance testing of a single train will result in the availability of two independent trains. Therefore, the recommendations of the section do not apply to the SHNPP.
GL-1 Automatic Initiation of AFS	See compliance statement for GL-5.
GL-2 Single Valves in the AFS Flow Path	The AFS pump suction primary water supply flows through a single locked open manually operated gate valve as shown on FSAR Figure 10.1.0-4. The alternate water supply connects to the AFS piping downstream of the above valve. The alternate supply lines are each provided with two safety related motor operated butterfly valves, normally closed, which are capable of remotely being opened from the Main Control Room. The Technical Specifications require verification that each valve in the AFS flowpath that is not locked, sealed, or otherwise secured in position, is in its correct position.
GL-3 Elimination of AFS Dependency of Alternating Current Power Following a Complete Loss of Alternating Current Power	The loss of all AC power will not affect the capability of the turbine-driven pump to supply water to the steam generators for at least two hours as described in Sections 10.4.9.2.3, 8.3 and 7.3.1.3.3. All supply and discharge valving is powered from redundant vital DC busses to include safety grade DC supply to the turbine controller and T&T valve. Turbine driven AFW pump bearing lube oil cooling is provided by a portion of the discharge flow from the turbine driven AFW pump. No electrically powered cooling pumps are required for the turbine pump bearing lube oil cooling.

TABLE 10.4.9B-4 AFS COMPLIANCE WITH NRC SHORT AND LONG TERM RECOMMENDATIONS

Recommendation	Compliance
GL-4 Prevention of Multiple Pump Damage Due to Loss of Suction Resulting From Natural Phenomena	The AFS is capable of withstanding the effects of natural phenoma such as earthquakes, tornadoes, hurricanes, and floods. In addition, all components of the AFS, except the CST, are located within the Reactor Auxiliary Building and the Containment Building which provide protection against the effects of externally generated missiles. The CST is classified as safety class 3, seismic Category I and its concrete enclosure protects the tank from tornado, hurricane and missile damage. See FSAR Sections 10.4.9.3 and 9.2.6.3.
GL-5 Non-Safety Grade, Non-Redundant AFS Automatic Initiation Signals	1)The motor driven AFW pumps are automatically started by any one of the Signals following signals: a) safety-injection signal b) low-low water level in any steam generator c) loss of power (under voltage) on the emergency bus d) loss of both feedwater pumps The turbine driven AFW pump is automatically started by either of the following signals: a) loss of power (under voltage) on the emergency bus (E) b) low-low water level in two out of three steam generators 2) The instrumentation and controls of the components and equipment in Train A are physically and electrically separate and independent of the instrumentation and controls of the components and equipment in Train B. The AFS is capable of performing its intended safety function despite the single failure of any component. 3) Testability of initiation signals has been included in the design, except loss of both feedwater pumps (1.d above). 4) The initiation signals and circuits are powered from the ESF electrical AC power distribution system. 5) Manual initiation and operation of the AFS is provided in the Control Room. A single failure in the manual circuits will not result in the loss of system function. 6) Upon loss of offsite power, the motor driven pumps are automatically started and powered from the respective diesel generators. 7) The automatic initiation signals and circuits are designed so that a single failure will not result in loss of manual capability to operate the AFS from the Control Room. See FSAR Section 7.3.1.3.3.

FIGURE 10.1.0-7

HEAT BALANCE AND MAXIMUM DESIGN LOAD

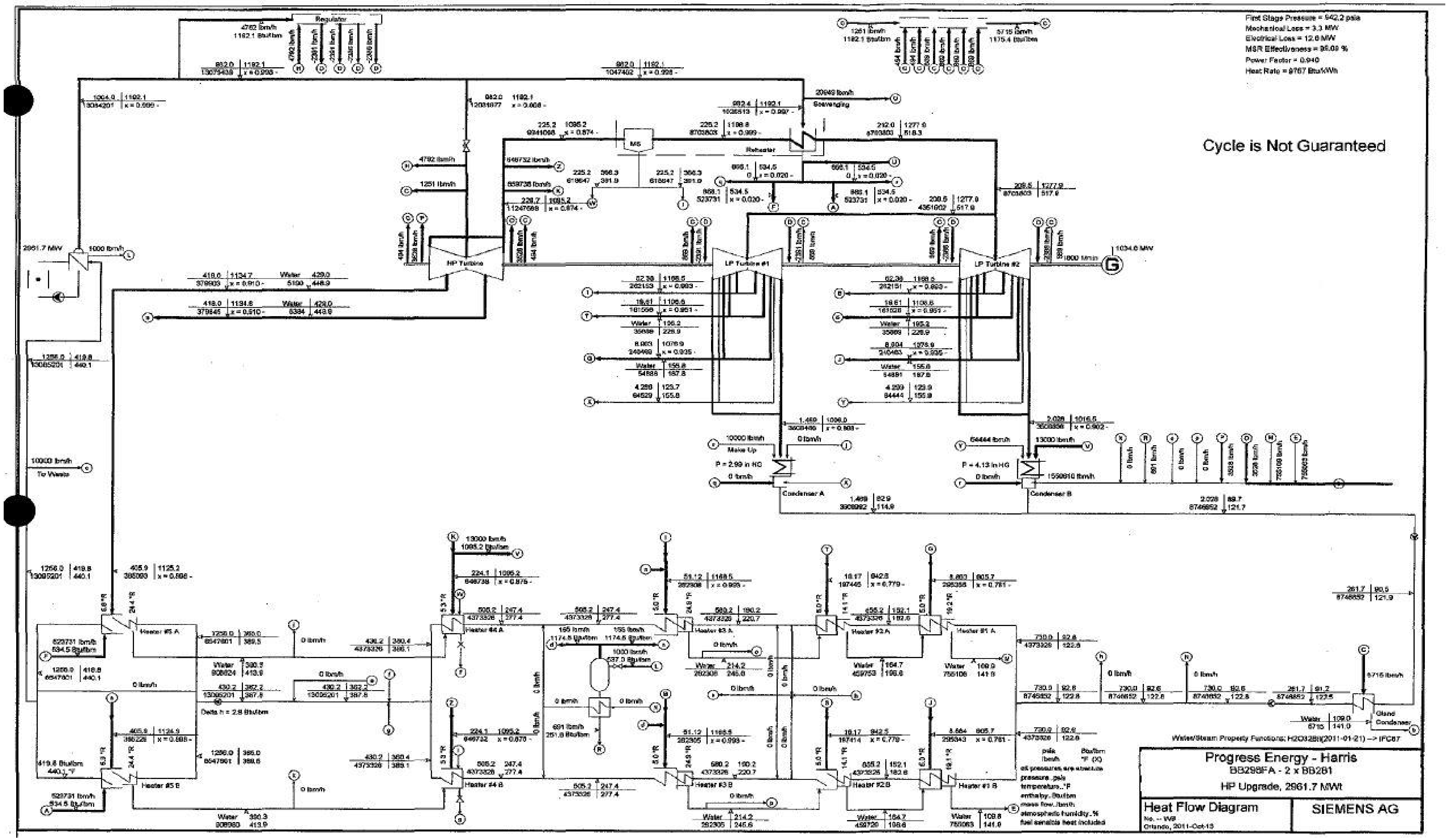

FIGURE 10.1.0-9

HEAT BALANCE LEGEND

IN HGA	– PRESSURE IN INCHES OF MERCURY REFERENCED TO Ø PRESSURE
W	– FLOW IN LB/HR
P	– PRESSURE IN PSIA
M	– MOISTURE IN %
T	– TEMPERATURE IN °F
h	– SPECIFIC ENTHALPY OF WATER IN BTU/LB
H	– SPECIFIC ENTHALPY OF STEAM IN BTU/LB
A & B	– STEAM CHEST LEAKOFFS
E	– REHEATER STEAM SUPPLY
F1	– REHEATER DRAIN
F2	– REHEATER SCAVENGING STEAM & DRAIN
M & N	– TOTAL HP SHAFT LEAKOFFS
H	– REGULATOR SUPPLY
P	– STEAM GENERATOR BLOWDOWN
Q	– SYSTEM LEAKAGE
S	– LOW PRESSURE GLAND SUPPLY
T	– LOW PRESSURE GLAND LEAKOFF
X	– STEAM GENERATOR BLOWDOWN TO CONDENSER
TEP	– ENTHALPY AT TURBINE END POINT IN BTU/LB
ELEP	– ENTHALPY AT EXPANSION LINE END POINT
TV	– TRIP AND THROTTLE VALVE
CV	– CONTROL VALVE
———	– CONDENSATE OR FEEDWATER LINE
— — —	– STEAM LINE
HP	– HIGH PRESSURE
LP	– LOW PRESSURE
HTR	– HEATER
GC	– GLAND STEAM CONDENSER
IV	– INTERCEPT VALVE
RSV	– REHEAT STOP VALVE
	– PUMP
DC	– DRAIN COOLER

FIGURE 10.2.2-4

STEAM CHEST DETAIL WITH CONTROL AND THROTTLE VALVE

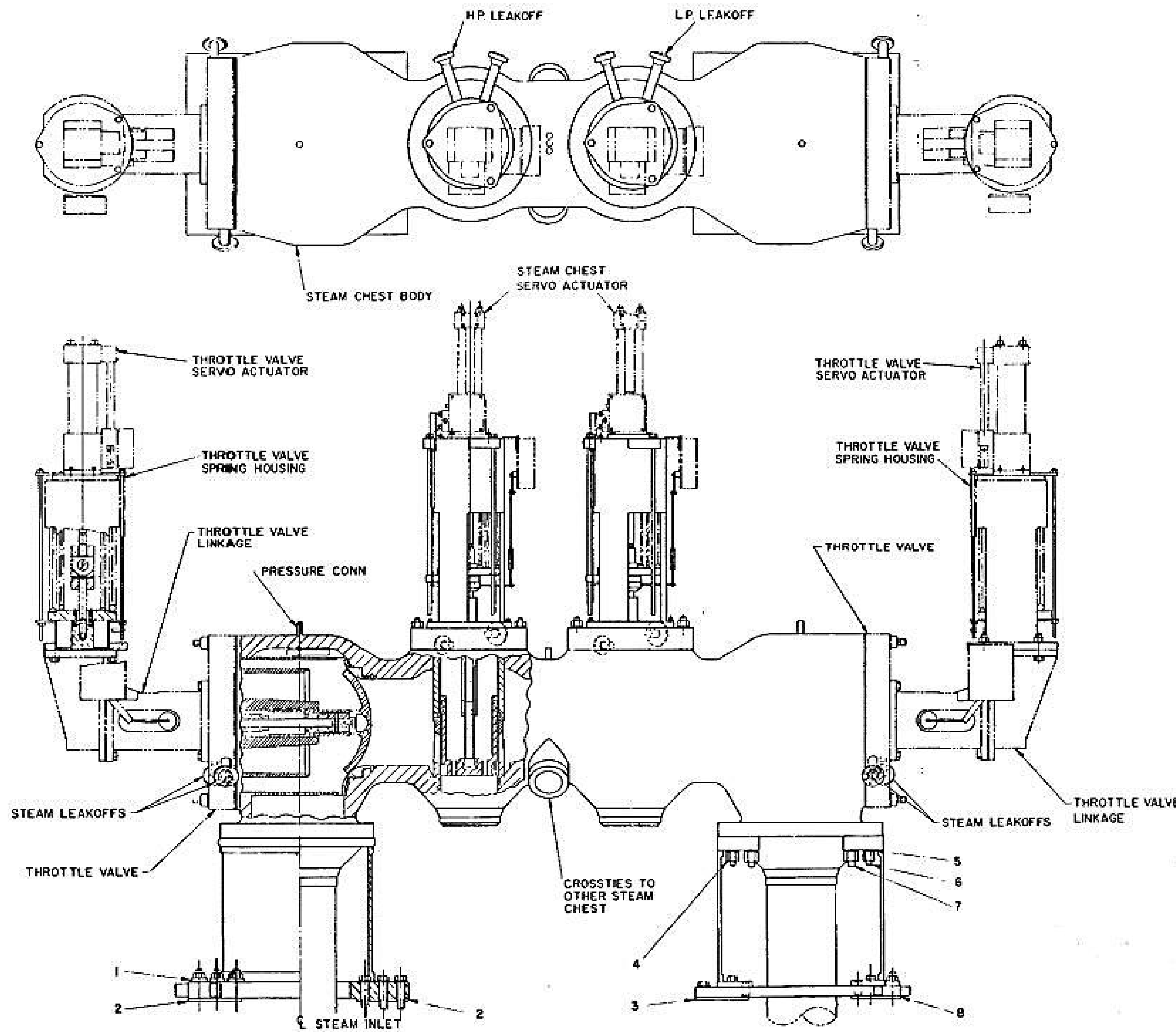

FIGURE 10.2.2-10

EMERGENCY TRIP SYSTEM DIAGRAM

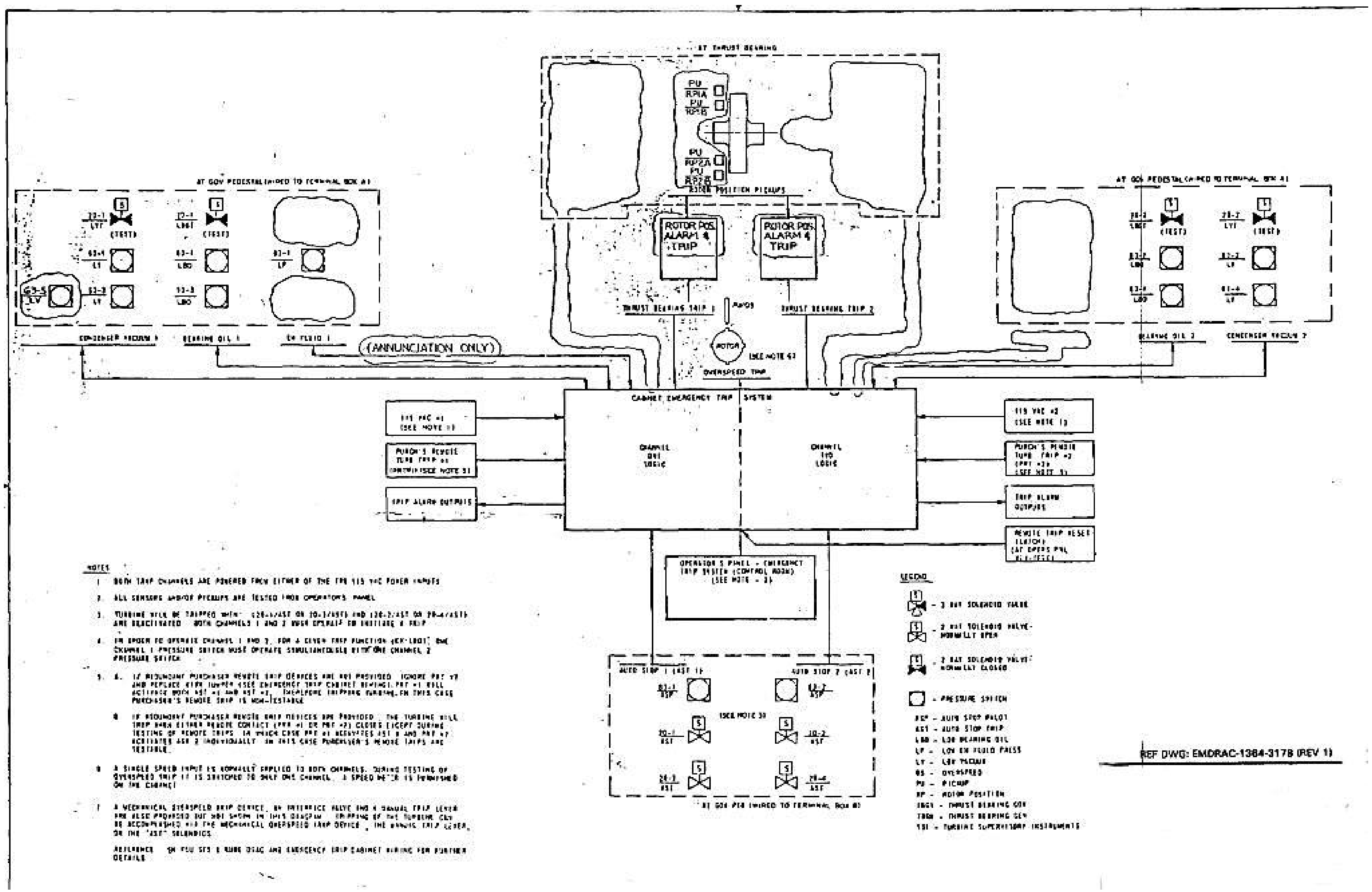

FIGURE 10.4.9B-1

STATION BLACKOUT

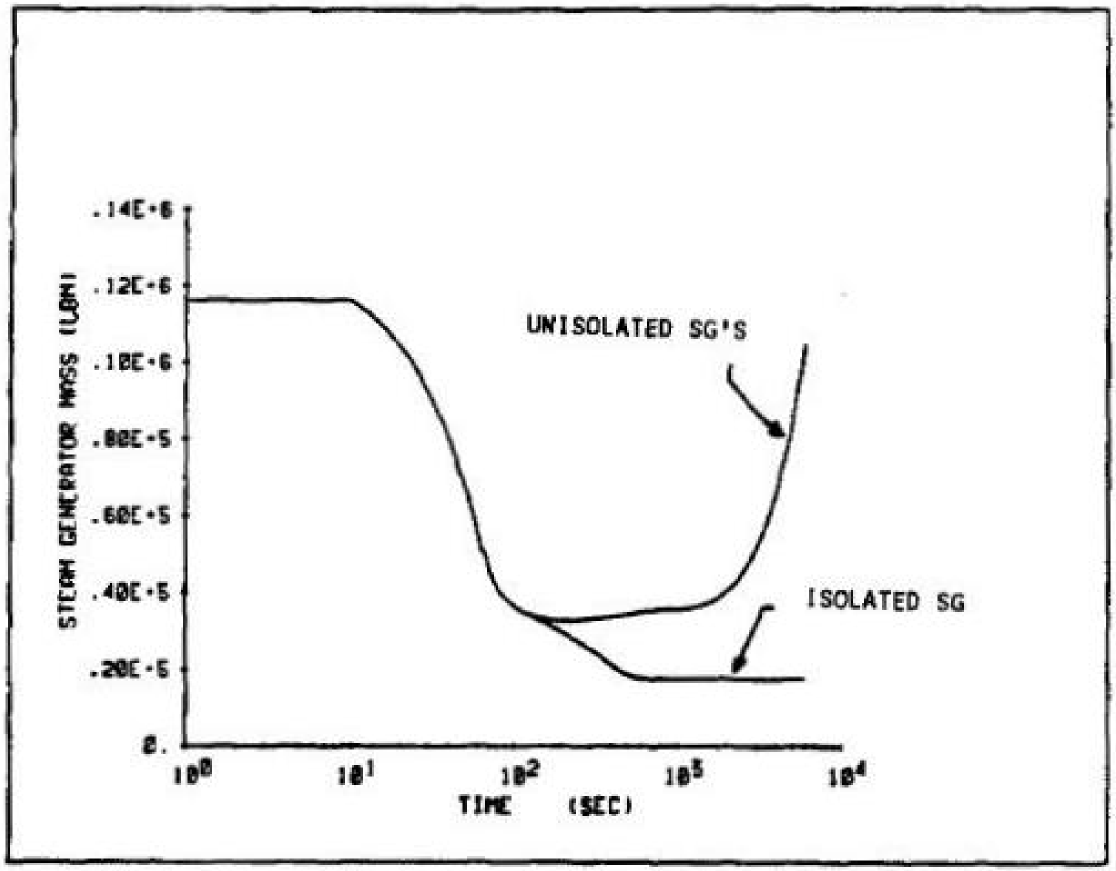

FIGURE 10.4.9B-2

MAIN FEEDLINE BREAK