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An Assessment of the Safety Implications of Control at the Calvert Cliffs-1 Nuclear Plant
Volume 2: Appendices

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AN ASSESSMENT OF THE SAFETY IMPLICATIONS OF CONTROL AT THE CALVERT CLIFFS-1 NUCLEAR PLANT
Volume 2: APPENDICES

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ACRONYMS

ac	alternating current
ADV	atmospheric steam dump valve
AFAS	auxiliary feedwater actuation system
AFW	auxiliary feedwater
BG&E	Baltimore Gas and Electric
B&W	Babcock and Wilcox
CE	Combustion Engineering
CEA	control element assembly
CEDM	control element drive mechanism
CEDS	control element drive system
CIS	containment isolation signal
CSAS	containment spray actuation signal
CVC	chemical and volume control
CVCS	chemical and volume control system
dc	direct current
dP	differential pressure
ECCS	emergency core cooling system
E/I	voltage-to-current
E/P	Electric-to-pneumatic
EPRI	Electric Power Research Institute
EOP	Emergency Operating Procedure
ESF	engineered safety features
ESFAS	engineered safety features actuation system
FMEA	Failure Mode and Effects Analysis
FSAR	final safety analysis report
FW	feedwater
gpm	gallons per minute
HP	high pressure
hp	horsepower
HPI	high-pressure injection
HPSI	high pressure safety injection
I/I	current-to-current
IA	instrument air
kV	kilovolts
kW	kilowatts
LER	Licensee Event Report
LOCA	loss-of-coolant accident
LOCI	loss-of-coolant incident
LP	low pressure

ACRONYMS (Continued)

LPI	low-pressure injection
LPSI	low-pressure safety injection
MCC	motor control center
MFW	main feedwater
MMS	modular modeling system
MSIV	main steam isolation valve
NIS	nuclear instrumentation system
NNI	nonnuclear instrumentation
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
ORNL	Oak Ridge National Laboratory
PA	plant air
PORV	power-operated relief valve
PPS	plant protection system
psia	pounds per square inch (absolute)
psid	pounds per square inch (differential)
psig	pounds per square inch (gage)
PTS	pressurized thermal shock
PWR	pressurized water reactor
RAS	recirculation actuation signal
RCP	reactor coolant pump
RCS	reactor coolant system
RPS	reactor protection system
RRS	reactor regulating system
RWT	refueling water tank
ry	reactor year
SAIC	Science Applications International Corporation
SDS	shutdown sequence
SG	steam generator
SGIS	SG isolation signal
SGTR	SG tube rupture
SI	safety injection
SIAS	safety injection actuation signal
SICS	safety implications of control systems
SLB	steam line break
SRW	service water
T_{avg}	temperature (average)
T_{ref}	desired reactor coolant average temperature
TBV	turbine bypass valve
V	volts
VCT	volume control tank

APPENDIX A

SELECTION OF SYSTEMS FOR ANALYSIS

The objective of this work, as discussed in Vol. 1, Sect. 2, is to conduct detailed FMEAs on control systems having a major impact on RCS overcooling, undercooling, or safety system performance. The method of achieving this objective consists of three steps:

1. Identify the Calvert Cliffs systems and functional interfaces.

2. Based on the methodology discussed in Section 3.1, identify those systems which have a potential impact on RCS overcooling, undercooling or safety system performance.

3. Conduct FMEAs of the systems identified in (2) above.

The impact of failures in many plant systems on plant transients is expected to be minor. Thus, the purpose of a plant-specific system list with identified interfaces is to aid in the selection of only those systems having a potential significant impact on plant response. Because of the large number of systems and components in a nuclear power plant, this preliminary screening is necessary to determine which systems require detailed analysis since it is not feasible to perform an in-depth study of all of them.

A.1 CALVERT CLIFFS SYSTEMS LIST

Based on a previously developed generic list of pressurized water reactor (PWR) systems[1] and the Calvert Cliffs Units 1 and 2 Final Safety Analysis Report (FSAR),[2] a list of Calvert Cliffs systems was developed. The generic systems and their associated subsystems have been grouped according to seven major functions:

1. Nuclear systems include the reactor core and those systems and subsystems which monitor and control core reactivity, remove heat from the core, and otherwise directly support the safe operation of the reactor.

2. Engineered safeguards systems include those systems, other than containment systems, used to mitigate the effects of reactor accidents such as those specified in the FSAR.

3. Containment systems include the reactor building and those systems needed to prevent reactor building overpressure, to prevent excessive leakage from the reactor building to the environment, and to provide a habitable atmosphere inside the reactor building.

4. Electrical systems including plant ac and dc electric power distribution circuitry.

5. Power conversion systems include the systems and components that transform or support the transformation of heat energy produced by the reactor core into electrical energy.

6. Process auxiliary systems include those systems and subsystems that support the plant systems directly involved in the operation of the reactor coolant systems.

7. Plant auxiliary systems provide support to other plant activities and personnel.

The generic PWR systems and functionally corresponding Calvert Cliffs systems are listed in Tables A1 through A7. These tables correspond to the seven major system functions discussed above. In addition to listing the generic and corresponding Calvert Cliffs systems, Tables A1 through A7 list the criteria for selection or elimination based on the control systems analysis scope considerations discussed in Sect. 3.1 of Vol. 1.

The nuclear systems, listed in Table A1, consist of the reactor core, the RCS and associated control systems, and the interfacing systems that recirculate reactor coolant. Of the nuclear systems, only the chemical and volume control system (CVCS), the RCS, and associated control instrumentation subsystems were retained for failure modes analysis. It should be noted that systems not selected for FMEA are eliminated only to the extent that failures of these systems are not postulated independently of other initiating control system failures.

The engineered safety features actuation systems (ESFAS) have been identified principally as safety systems as shown in Table A2. The only possible exceptions are the auxiliary control panels. Although these panels perform standby safety-related functions, it is not known whether they are safety qualified based on available information. They are eliminated based on their safety functions.

The containment systems are listed in Table A3. Most containment systems are safety systems. However, the containment air recirculation and cooling system, although safety qualified, performs the containment cooling functions during normal operation. In addition, the containment purge system and the pressurizer compartment cooling equipment have also been retained.

The power conversion systems are included in total as shown in Table A5. The operating status of these control systems is expected to have a

Table A1. Identification and first-stage selection of Calvert Cliffs nuclear systems

Generic PWR Nuclear Systems		Corresponding Calvert Cliffs Nuclear Systems		Non-Exclusion Criteria		Exclusion Criteria	
N01	Reactor Core	N01	Reactor Core			N01	The reactor core is a safety system
N02	Control Rod Drive System	N02	Control Element Drive Mechanisms (CEDM)			N02	CEDM do not influence transients following reactor trip
N03	Reactor Control System	N03	Control Element Drive System (CEDS)			N03	CEDS does not influence transients following reactor trip
N04	Reactor Coolant System (including reactor vessel and internals)	N04	Reactor Coolant System (RCS)	N04	Response of RCS provides the basis for evaluating control system failures		
		N04.A	Reactor Regulating System				
		N04.B	Reactor Coolant Pressure Regulating System				
N05	Emergency Boration System	N05	Chemical and Volume Control System (CVCS) (see N09)			N05	Emergency Boration is a safety function (see N09, CVCS)

Table A1. (continued)

Generic PWR Nuclear Systems		Corresponding Calvert Cliffs Nuclear Systems		Non-Exolusion Criteria	Exclusion Criteria	
N06	Reactor Protection System	N06	Reactor Protective System (RPS)		N06	The RPS is a safety system which has no funotion following reaotor trip
N07	Nuclear Monitoring/ Nuclear Instrumentation System	N07	Nuclear Instrumentation System (NI)		N07	The NI has no function following reactor trip
N08	Residual Heat Removal/ Low Pressure Safety Injection System	N08	Shutdown Cooling System		N08	The Shutdown cooling system is used only following plant shutdown and depres-surization

Table A1. (continued)

Generic PWR Nuclear Systems	Corresponding Calvert Cliffs Nuclear Systems	Non-Exclusion Criteria	Exclusion Criteria
N09 Chemical and Volume Control System	N09 Chemical and Volume Control System (CVCS) (see N05)	N09 The CVCS directly interfaces with the RCS	
	N09.A Pressurizer Level Regulating System	N09.A The Pressurizer Level Regulating system controls flow to and from the RCS	
	N09.B Reactor Regulating System (see N04.A)	N09.B The Reactor Regulating System establishes the pressurizer level setpoint	
	N09.C Electric Heat Tracing	N09.C No basis for elimination	

Table A2. Identification and first-stage selection of Calvert Cliffs engineered safety features actuation systems

Generic PWR Engineered Safety Features Systems		Corresponding Calvert Cliffs Safety Features Systems		Non-Exclusion Criteria	Exclusion Criteria	
S02	Engineered Safety Features Actuation System	S02	Engineered Safety Features Actuation System (ESFAS)		S02	The ESFAS is a safety system
S03	Safety Injection System	S03	Safety Injection System		S03	The Safety Injection Systems are Safety Systems
S03.A	High Pressure Safety Injection Subsystem	S03.A	High Pressure Safety Injection Subsystem (HPSI)			
S03.B	Safety Injection Tank/Core Flood Subsystem	S03.B	Safety Injection Tanks			
S03.C	Low Pressure Safety Injection Subsystem	S03.C	Low Pressure Safety Injection Subsystem (LPSI)			
S04	Remote Shutdown System	S04	Auxiliary Control Panels		S04	Assumed to be a safety system
S05	Auxiliary Feedwater System	S05	Auxiliary Feedwater System (AFS)		S05	The AFS is a safety system

Table A3. Identification and first-stage selection of Calvert Cliffs containment systems

Generic PWR Containment Systems		Corresponding Calvert Cliffs Containment Systems		Non-Exclusion Criteria		Exclusion Criteria	
C02	Reactor Building/ Containment and Penetrations	C02	Containment Structure			C02	The containment structure and penetrations are safety systems
C03	Containment Cooling System	C03	Containment Air Recirculation and Cooling System (see C08)	C03	Although a safety system, the Containment Air Recirculation and Cooling System provides cooling during normal operation		
C04	Containment Isolation is a function of the Engineered Safety Features Actuation System and the various piping systems which penetrate containment	C04	Isolation System			C04	The Containment Isolation System is a safety system
C05	Containment Purge System	C05	Containment Purge System	C05	No basis for elimination		
C07	Combustible Gas Control System	C07.A	Electric Hydrogen Recombiner			C07	Hydrogen Control Systems are safety systems
		C07.B	Hydrogen Purge System				

Table A3. (continued)

Generic PWR Containment Systems		Corresponding Calvert Cliffs Containment Systems		Non-Exclusion Criteria		Exclusion Criteria	
C08	Containment Ventilation System	C08	Containment Air Recirculation and Cooling System (see C03)				
		C08.A	CEDM Cooling System			C08.A	The CEDM and their cooling system do not influence transients following reactor trip
		C08.B	Pressurizer Compartment Cooling	C08.B	No basis for elimination		
C10	Containment Spray System	C10.A	Containment Spray System			C10	The Containment Spray and Iodine Removal Systems are safety systems
		C10.B	Containment Iodine Removal System				
C11	Penetration Room Ventilation System	C11	Containment Penetration Room Ventilation System			C11	The Containment Penetration Room Ventilation System is a safety system

Table A4. Identification and first-stage selection of Calvert Cliffs electrical systems

Generic PWR Electrical Systems		Corresponding Calvert Cliffs Electrical Systems		Non-Exclusion Criteria		Exclusion Criteria	
E01	Main Power System	E01	500 KV Switchyard and Unit Transformer (see E07)	E01	Electrical System		
E02	Plant AC Distribution System	E02	13,000, 4160 and 480 Volt Station Distribution Systems	E02	Electrical System		
E03	Instrumentation and Control Power Systems	E03	125 Volt DC and Instrument AC Systems	E03	Electrical System		
E04	Emergency Power System	E04	Emergency Diesel Generators			E04	Safety System
E05	Plant Lighting System	E05	Specific System Unidentified			E05	Not necessary in responding to plant transients
E06	Plant Computer	E06	Plant Computer	E06	No basis for elimination		

Table A5. Identification and first-stage selection of Calvert Cliffs power conversion systems

Generic PWR Power Conversion Systems		Corresponding Calvert Cliffs Power Conversion Systems		Non-Exclusion Criteria		Exclusion Criteria
P01	Main Steam System	P01	Main Steam System (see P03)	P01	Direct Interface with Steam Generators	
P02	Turbine-Generator System	P02	Turbine Generator and Condenser System (see P04.A)	P02	Direct Interface with Main Steam and Condensate and Feedwater Systems	
		P02.A	Turbine Generator Control System			
P03	Turbine Bypass System	P03	Main Steam System (see P01)	P03	Direct Interface with Steam Generators	
		P03.A	Steam Dump and Turbine Bypass Control System			
		P03.B	Reactor Regulating System (see N04.A)			
P04	Condenser and Condensate System	P04.A	Turbine Generator and Condenser System (see P02)	P04.A	See P02, Turbine Generator and Condenser System	
		P04.B	Condensate and Feedwater System (see P05)	P04.B	Direct Interface with Steam Generators	

Table A5. (continued)

Generic PWR Power Conversion Systems		Corresponding Calvert Cliffs Power Conversion Systems		Non-Exclusion Criteria		Exclusion Criteria
P05	Feedwater System	P05	Condensate and Feedwater System (see P04.B)	P05	See P04.B, Condensate and Feedwater System	
		P05.A	Feedwater Regulating System			
P06	Circulating Water System	P06	Circulating Salt Water Cooling System	P06	Direct Interface with Turbine Generator and Condenser System	
P07	Steam Generator Blowdown System	P07	Steam Generator Blowdown System	P07	Direct Interface with Steam Generators	
P08	Auxiliary Steam System	P08	Auxiliary Boiler Steam System	P08	No Basis for Elimination	

Table A6. Identification and first-stage selection of Calvert Cliffs process auxiliary systems

Generic PWR Process Auxiliary Systems		Corresponding Calvert Cliffs Process Auxiliary Systems		Non-Exclusion Criteria		Exclusion Criteria
W01	Radioactive Waste System	W01	Waste Processing Systems	W01	No basis for elimination	
W01.A	Gaseous Radwaste System	W01.A	Waste Gas Processing System			
W01.B	Liquid Radwaste System	W01.B1	Reactor Coolant Waste Processing System (see W04.A)			
		W01.B2	Miscellaneous Waste Processing System			
W01.C	Solid Radwaste System	W01.C	Solid Waste Processing System			
W02	Radiation Monitoring System	W02	Radiation Monitoring System	W02	No basis for elimination	
W03	Cooling Water Systems	W03	Cooling Water Systems	W03	Cooling water systems are required for the operation of other key systems	
W03.A	Reactor Building Cooling Water System	W03.A	Component Cooling Water System			
W03.B	Turbine Building Cooling Water System	W03.B	Service Water System			

Table A6. (continued)

Generic PWR Process Auxiliary Systems	Corresponding Calvert Cliffs Process Auxiliary Systems	Non-Exclusion Criteria	Exclusion Criteria
W04 Service Water Systems	W04 Cooling Water Systems	W04 Service and Cooling Water Systems are required for the operation of other key systems	
W04.A Demineralized Makeup Water System	W04.A Reactor Coolant Waste Processing System (see W01.B)		
W04.B Station Service Water System	W04.B Salt Water System		
W04.C Chilled Water System	W04.C Function provided as parts of the Plant Ventilating System where applicable		
W05 Refueling System	W05 Reactor Component Handling Equipment		W05 Reactor Component Handling Equipment is in operation only during reactor cold shutdown
W06 Spent Fuel Storage System	W06 Spent Fuel Storage System	W06 No basis for elimination	
W06.A Fuel Pool Cooling and Cleanup System	W06.A Spent Fuel Pool Cooling System		

Table A6. (continued)

Generic PWR Process Auxiliary Systems		Corresponding Calvert Cliffs Process Auxiliary Systems		Non-Exclusion Criteria		Exclusion Criteria
W07	Compressed Air System	W07	Compressed Air System	W07	Compressed Air Systems are required for the operation of other key systems	
W07.A	Service Air System	W07.A	Plant Air System			
W07.B	Instrument Air System	W07.B	Instrument Air System			
W08	Process Sampling System	W08	Sampling System	W08	No basis for elimination	
W09	Plant Gas System	W09.A	Hydrogen Gas System	W09	No basis for elimination	
		W09.B	Nitrogen Gas System			

Table A7. Identification and first-stage selection of Calvert Cliffs auxiliary systems

Generic Plant Auxiliary Systems		Corresponding Calvert Cliffs Auxiliary Systems		Non-Exclusion Criteria		Exclusion Criteria
X01	Potable and Sanitary Water System	X01	Specific system not identified from available information	X01	No basis for elimination	
X02	Fire Protection System	X02	Fire Protection System	X02	No basis for elimination	
X03	Communications System	X03	Plant Communications System	X03	No basis for elimination	
X04	Security System	X04	Specific systems not identified from available information	X04	No basis for elimination	
X05	Heating, Ventilating, and Air Conditioning Systems	X05	Plant Ventilating Systems			
X05.A	Control Room Habitability System	X05.A	Control and Cable Spreading Rooms Ventilating System (see X05.D1)	X05.A	Although a safety system, the Control and Cable Spreading Room Ventilation System provides cooling during normal operation	

Table A7. (continued)

Generic Plant Auxiliary Systems	Corresponding Calvert Cliffs Auxiliary Systems	Non-Exclusion Criteria	Exclusion Criteria
X05.B Turbine Building Ventilation System	X05.B1 Turbine Building Ventilating System	X05.B1 No basis for elimination	
	X05.B2 Auxiliary Feedwater Pump Room Emergency Cooling System		X05.B2 Safety System
X05.C Diesel Building Ventilation System	X05.C Diesel Generator Rooms Ventilating System (see X05.D4)		X05.C Safety System

Table A7. (continued)

Generic Plant Auxiliary Systems	Corresponding Calvert Cliffs Auxiliary Systems	Non-Exclusion Criteria	Exclusion Criteria
X05.D Auxiliary Building Ventilation System	X05.D Auxiliary Building Ventilating Systems		
	X05.D1 Control and Cable Spreading Room Ventilating System (see X05.A)	X05.D1 See X05.A	
	X05.D2 Access Controlled Area Ventilating Systems	X05.D2 No basis for elimination	
	X05.D3 Switchgear Rooms Ventilating System		X05.D3 Safety System used to cool electrical equipment
	X05.D4 Diesel Generator Rooms Ventilating System (see X05.C)		X05.D4 Safety System
	X05.D5 Spent Fuel Pool Ventilating System (see X05.E)	X05.D5 No basis for elimination	
	X05.D6 Radwaste Area Ventilating System	X05.D6 No basis for elimination	
	X05.D7 ECCS Pump Room Ventilating System		X05.D7 Safety System

Table A7. (continued)

Generic Plant Auxiliary Systems		Corresponding Calvert Cliffs Auxiliary Systems		Non-Exclusion Criteria		Exclusion Criteria
X05.E	Fuel Building Ventilation System	X05.E	Spent Fuel Pool Ventilating System (see X05.D5)	X05.E	No basis for elimination	
X06	Non-Radioactive Waste System	X06	Included in W01, Waste Processing Systems	X06	No basis for elimination	

significant effect on the post reactor-trip RCS overcooling and insufficient core cooling failure modes.

With the exception of the reactor component handling system, which operates only during cold shutdown states, the process auxiliary systems have been retained. The process auxiliary systems are listed in Table A6.

The auxiliary systems are listed in Table A7. With the exception of qualified ventilation systems, used exclusively to cool safety systems, the auxiliary systems have been retained.

A.2 RCS INTERFACING SYSTEMS

The Calvert Cliffs systems not excluded based on scope considerations are examined further to assess their functional relationship to RCS transient response. This functional relationship is assessed in two steps:

1. Control systems having a direct interface with the RCS are selected for FMEA.

2. Control systems having a direct interface with any of the systems directly interfacing with the RCS are selected for FMEA.

These assessments are discussed below.

A.2.1 Systems Directly Interfacing With the RCS

The Calvert Cliffs systems selected for analysis as shown in Tables A1 through A7 were examined individually to evaluate whether they interfaced directly with the RCS. If an RCS interface could be identified, the system was selected for FMEA.

Table A8 lists all nuclear, safety features, electrical, and containment systems found to be within the scope of this control systems analysis. The RCS interface of each is characterized. As shown in Table A8, all applicable systems were found to have an RCS interface with the exception of the Containment Purge system.

Table A9 lists the selected power conversion systems and the RCS interface characteristics. As shown, the main steam, condensate and feedwater, feedwater regulating, and steam generator blowdown systems had direct RCS interfaces.

The process auxiliary systems and their RCS interface characteristics are listed in Table A10. As shown, only the component cooling water and the sampling system had direct RCS interface.

Table A8. RCS interfaces with applicable nuclear, safety features, electrical, and containment systems

System Number	Calvert Cliffs System Name	RCS Interface Characterization
N04	Reactor Coolant System	--
N04.A	Reactor Regulating System	Direct Interface, Part of RCS
N04.B	Reactor Coolant Pressure Regulating System	Direct Interface, Part of RCS
N09 and N09.A, N09.B, and N09.C)	Chemical and Volume Control System	Interactive Interface
S04	Auxiliary Control Panel and Other Local Control Panels	Potential Interfaces with Pressurizer and CEDM
E06	Plant Computer	Interfaces with RCS Instrumentation
C03	Containment Air Recirculation and Cooling System	Provide cooling for pressurizer components, CEDM and in-containment RCS instrumentation components
C05	Containment Purge System	No Interface with RCS
C08.B	Pressurizer Compartment Cooling	The Pressurizer Compartment Cooling equipment consists of passive ductwork used to cool the pressurizer compartment

Table A9. RCS interfaces with power conversion systems

System Number	Calvert Cliffs System Name	RCS Interface Characterization
P01	Main Steam System (Including Steam Dump and Turbine Bypass Valves)	Interactive Interface
P03.A	Steam Dump and Turbine Bypass Control System	No interface with RCS
P02	Turbine Generator and Condenser System	No interface with RCS
P02.A	Turbine Generator Control System	No interface with RCS
P05	Condensate and Feedwater System	Interactive Interface
P05.A	Feedwater Regulating System	Interactive Interface
P06	Circulating Salt Water Cooling System	No interface with RCS
P07	Steam Generator Blowdown System	Interfaces with Steam Generators
P08	Auxiliary Boiler Steam System	No interface with RCS

Table A10. RCS interfaces with process auxiliary systems

System Number	Calvert Cliffs System Name	RCS Interface Characterization
W01.A	Waste Gas Processing System	No Interface with RCS
W01.B1	Reactor Coolant Waste Processing System	No Interface with RCS
W01.B2	Miscellaneous Waste Processing System	No Interface with RCS
W01.C	Solid Waste Processing System	No Interface with RCS
W02	Radiation Monitoring System	No Interface with RCS
W03.A	Component Cooling Water System	RCS Interface
W03.B	Service Water System	No Interface with RCS
W04.B	Salt Water System	No Interface with RCS
W06	Spent Fuel Storage System	No Interface with RCS during reactor operation
W06.A	Spent Fuel Pool Cooling System	No Interface with RCS
W07.A	Plant Air System	No Interface with RCS
W07.B	Instrument Air System	No Interface with RCS
W08	Sampling System	RCS Interface
W09.A	Hydrogen Gas System	No Interface with RCS
W09.B	Nitrogen Gas System	No Interface with RCS

Of the auxiliary systems listed in Table A11, none had a direct RCS interface.

A.2.2 Systems Indirectly Interfacing With the RCS

Of the Calvert Cliffs systems identified, systems have been selected for FMEA based on a direct interface with the RCS. These systems are listed in Tables A8 through A11. However, systems not interfacing with the RCS, but required for the operation of one that does, can have a significant influence on RCS response. For this reason, secondary interface systems also are selected for FMEA.

In Table A12, each of the primary RCS interface systems is listed. The systems that interface with these systems and the interface characterizations are listed for each primary RCS interface system. These primary and secondary interface systems represent systems selected for FMEA. For convenience, systems selected for FMEA are listed only once even though they may have interfaces with several systems.

For four primary interface systems, feedwater regulation, pressurizer compartment cooling, sampling, and the plant computer, no additional interface systems other than those previously listed were found. Due to the extensive number of possible interfaces, especially with the plant computer and the sampling system, a more detailed analysis than the current screening analysis may be required. For this reason, the FMEA to be performed on these systems also will serve to identify additional interfacing systems of importance if they exist.

A.3 SAFETY SYSTEM INTERFACING SYSTEMS

Since the identification of control system failures which degrade safety functions is a major objective of this program, safety system interfacing systems were evaluated for possible selection. For those safety systems already selected in Table A12, the FMEA will identify and examine the interfacing systems and the extent of their interaction.

In order to identify safety system interfacing systems, a review of the interfaces with those safety systems previously identified was undertaken. Those safety systems identified on the basis of their safety function in Tables A1 through A7 are listed in Table A13. Each safety system was reviewed to determine its interfaces. The interfacing systems identified were selected for FMEA only if they were (1) not a safety system, and (2) not previously selected for FMEA.

This review resulted in three additions to the list of systems selected for FMEA: the nitrogen gas, auxiliary boiler steam, and auxiliary building ventilating. All other safety system interfacing systems had either previously been selected for FMEA or were outside the scope of the current analysis program.

Table A11. RCS interfaces with auxiliary systems

System Number	Calvert Cliffs System Name	RCS Interface Characterization
X01	Potable and Sanitary Water	No Interface with RCS
X02	Fire Protection System	No Interface with RCS
X03	Communications System	No Interface with RCS
X04	Security System	No Interface with RCS
X05.A	Control and Cable Spreading Rooms Ventilation System	No Interface with RCS
X05.B1	Turbine Building Ventilating System	No Interface with RCS
X05.D2	Access Controlled Area Ventilating System	No Interface with RCS
X05.D5	Spent Fuel Pool Ventilating System	No Interface with RCS
X05.D6	Radwaste Area Ventilating System	No Interface with RCS

Table A12. Secondary interface systems

Primary RCS Interfacing System		Secondary Interfacing System		Interface Characterization
N04.A	Reactor Regulating System	No Additional Systems*		N/A
N04.B	Reactor Coolant Pressure Regulating System	No Additional Systems*		N/A
N09 (and N09.A, N09.B, and N09.C)	CVCS	W01.A	Waste Gas Processing System	Intermittent Venting of Volume Control Tank
		W01.B1	Reactor Coolant Waste Processing System	Reactor Coolant Diverted for Processing
		W01.C	Solid Waste Processing	Intermittent Disposal of Spent Resins
		W07.B	Instrument Air System	Required for the Operation of CVCS Valves
		W09.A	Hydrogen Gas System	Provides H_2 for Addition to Reactor Coolant Makeup
		X05.D2	Access Controlled Area Ventilating System	Cooling for CVCS Electrical Components
P01	Main Steam System	P03.A	Steam Dump and Turbine Bypass Control System	Control of Turbine Bypass and Atmospheric Dump Valves
		P02	Turbine Generator and Condenser System	Isolation of Steam Flow from Main Steam Lines
P05	Condensate and Feedwater System	P08	Auxiliary Boiler Steam System	Auxiliary Boiler Steam System is Used Only Following Plant Shutdown
		W03.B	Service Water System	Cooling Water for Feedwater and Condensate Pumps

Table A12. (continued)

Primary RCS Interfacing System		Secondary Interfacing System		Interface Characterization
		X05.B1	Turbine Building Ventilating System	Cooling for Turbine Building Electrical Components
P05.A	Feedwater Regulating System	No Additional Systems		N/A
P07	Steam Generator Blowdown System	W01.B2	Miscellaneous Waste Processing System	Processes Blowdown from Steam Generators
		W02	Radiation Monitoring System	Monitors Blowdown Radiation and Isolates Blowdown Line
C03	Containment Air Recirculation and Cooling System	C05	Containment Purge System	Cooling for Purge System Electrical Components
C08.B	Pressurizer Compartment Cooling	No Additional Systems		N/A
W03.A	Component Cooling Water System	W04.B	Salt Water System	Heat Sink for Component Cooling Water Heat Loads
W08	Sampling System	No Additional Systems*		N/A
E06	Plant Computer	No Additional Systems*		N/A

*Although additional interfacing systems could not be identified from available information, the possibility of additional interfacing systems and their characteristics will be reinvestigated in performing the FMEA's.

Table A13. Safety systems identified in Tables A1 through A7

System Number	Calvert Cliffs System Name
N01	Reactor Core
N06	Reactor Protective System
S02	Engineered Safety Features Actuation System
S03	Safety Injection System
S04	Auxiliary Control Panels
S05	Auxiliary Feedwater System
C02	Containment Structure
C04	Containment Isolation System
C07.A	Electric Hydrogen Recombiner
C07.B	Hydrogen Purge System
C10.A	Containment Spray System
C10.B	Containment Iodine Removal System
C11	Containment Penetration Room Ventilation System
X05.B2	Auxiliary Feedwater Pump Room Emergency Cooling System
X05.C	Diesel Generator Rooms Ventilating System
X05.D3	Switchgear Rooms Ventilating System
X05.D7	ECCS Pump Room Ventilating System

REFERENCES FOR APPENDIX A

1. "A Ranking of Nuclear Plant Systems for Failure Modes and Effects Analysis," ORNL #62B-13819C/62X-30, SAI #1-245-08-492-02, December 1982.

2. "Final Safety Analysis Report, Baltimore Gas and Electric Calvert Cliffs Nuclear Plant," December 1980.

APPENDIX B

SYSTEMS DESCRIPTIONS

System descriptions are summarized in this section for those systems upon which a component level FMEA was performed (see Vol. 1, Sect. 4.2). However, the system descriptions do not reflect all components included in a system. System components and capabilities built into the plant system but not used in actual operations have been omitted from consideration in this section. System components and capabilities not directly utilized in response to a transient have also been excluded.

B.1 REACTOR COOLANT SYSTEM

The reactor coolant system (RCS)[1] removes heat from the reactor core region and transfers it to the secondary system. The reactor coolant circulated in the system is borated water maintained above saturation pressure. The reactor coolant system is composed of the reactor vessel, two heat transfer loops, a pressurizer, and a quench tank. Each loop contains one steam generator, two reactor coolant pumps, connecting piping, and flow and temperature instrumentation. The pressurizer is connected to one of the two hot legs by a surge line for maintenance of RCS pressure.

The RCS is shown in Figs. B1 and B2. Four reactor coolant pumps force reactor coolant through the reactor vessel for heat removal and moderation of the core. Two hot legs carry the heated water from the reactor vessel to the steam generators, where heat is transferred to the secondary system water. Reactor coolant flow is returned to the reactor coolant pumps via four cold leg pipes (two leaving each steam generator). The RCS is designed for 2500 psia and 650°F, but normally operates at 2250 psia. Cold leg temperature is typically 548°F and hot leg temperature varies with power level up to 600°F.

The steam generators are inverted U-tube heat exchangers with the reactor coolant inlet and outlet at the bottom. A vertical divider plate separates the inlet and outlet plenums. Reactor coolant flows on the tube side while secondary-side water on the shell side absorbs the heat. Secondary-side water vaporizes to steam for use in the turbine generator. The steam generator tubes are designed to withstand a pressure differential of 1600 psi between the tube and shell sides.

On the primary side, a 1500 ft^3 pressurizer provides a surge volume for the control of reactor coolant volume and pressure. Volume and pressure variations caused by contraction or expansion of the reactor coolant occur with changes in power level, as well as with other factors

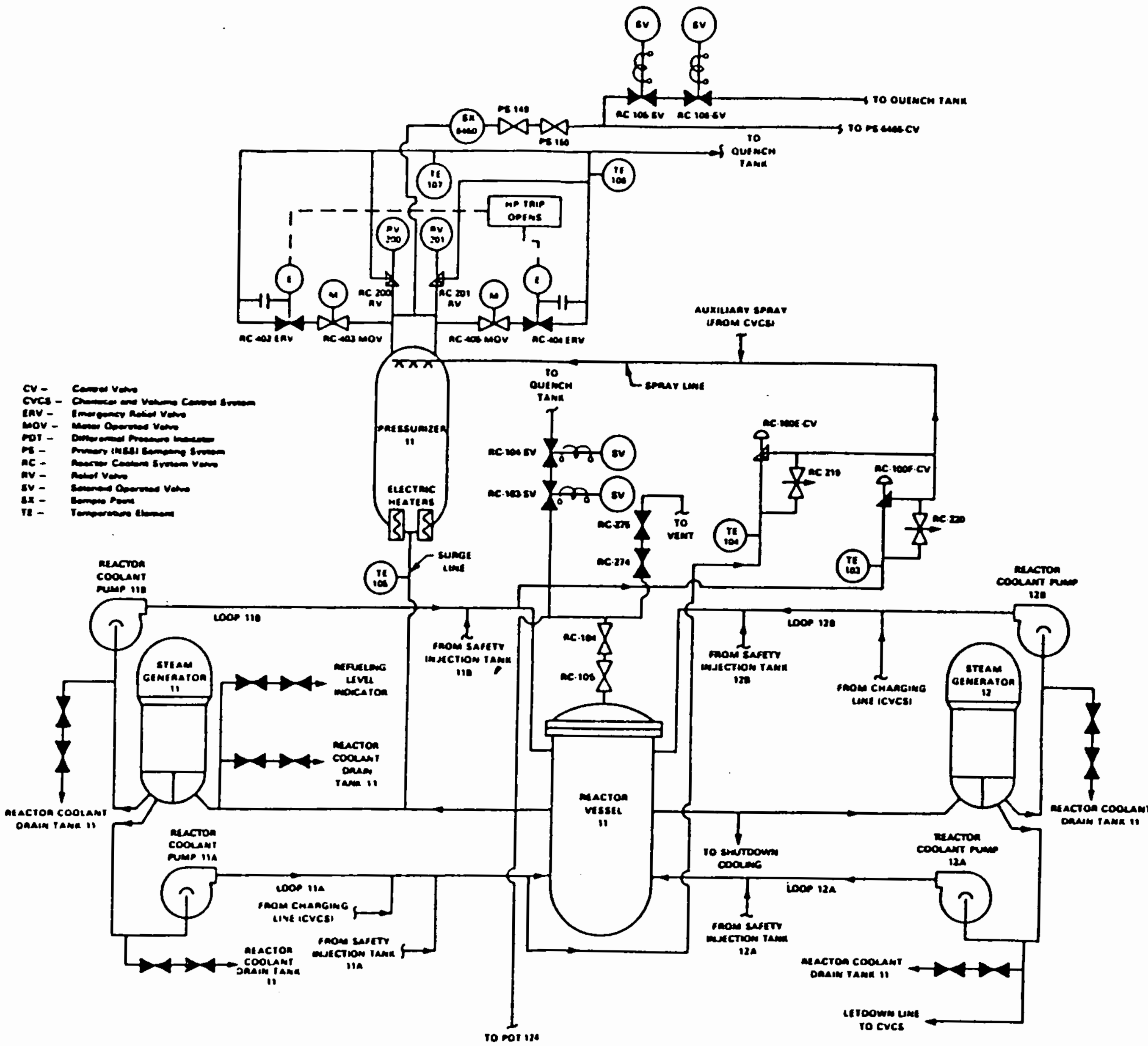


Fig. B1. RCS piping and instrumentation diagram.

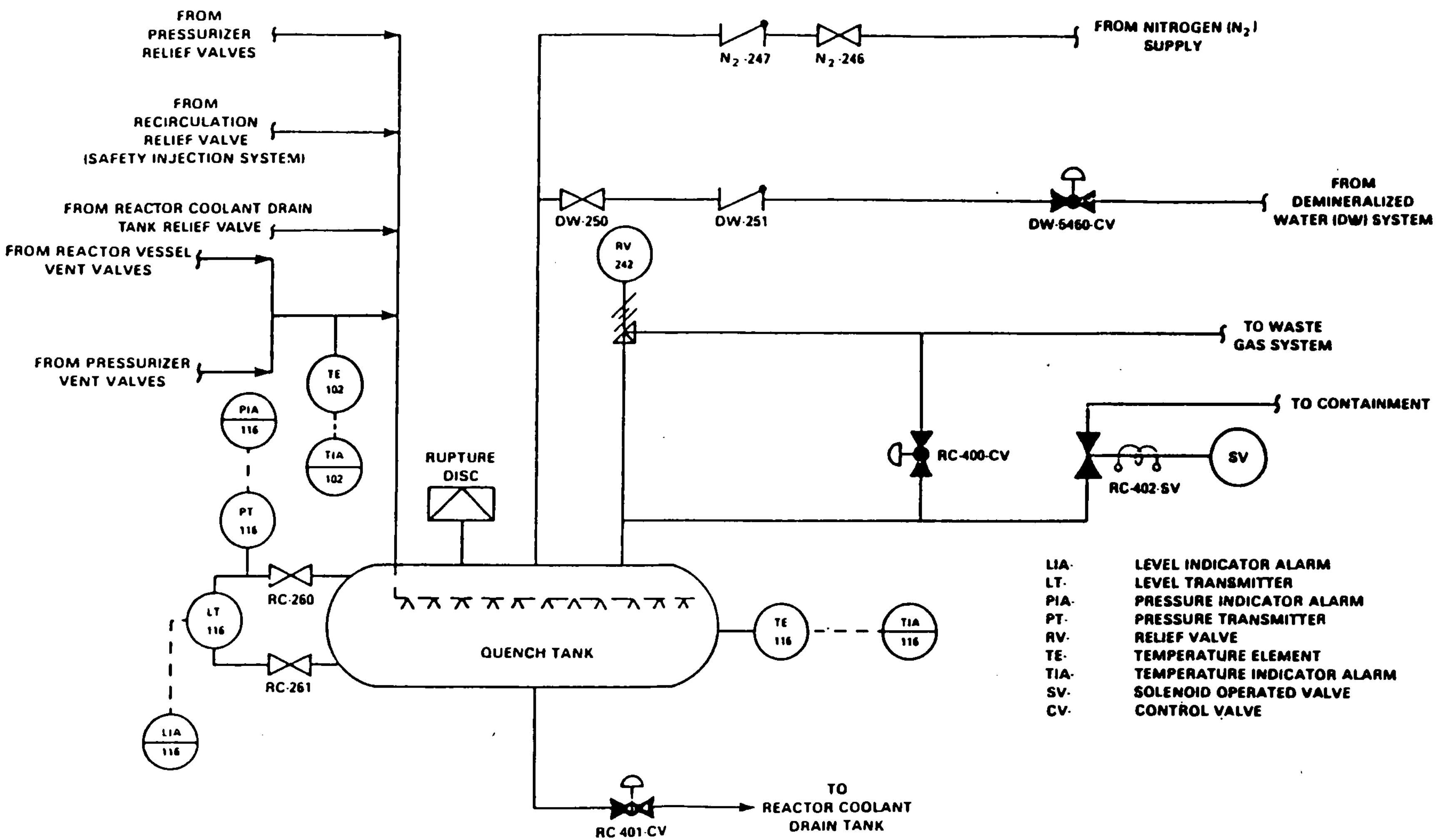


Fig. B2. Quench tank piping and instrumentation diagram.

including system heat loss and minor inventory losses. The pressurizer is equipped with electric heaters and automatic spray for either producing steam or condensing steam to maintain set-point pressure. Volume is maintained based on level indication in the pressurizer through variable makeup and letdown flow, provided to and from the RCS by the CVCS. In automatic mode, letdown and makeup are controlled by the pressurizer level regulating system.

The pressurizer is located at a higher elevation than the reactor coolant piping, so that during contraction of reactor coolant, the pressurizer will drain before voiding in the rest of the RCS can occur.

Two power-operated relief valves (PORVs) and two spring-loaded safety valves connected to the top of the pressurizer are used to provide protection from overpressure. The PORVs are set to open at 2385 psig and sized to be able to release sufficient pressurizer steam during abnormal operating occurrences to prevent opening of the reactor coolant system safety valves, which open at 2485 and 2550 psig respectively. The PORVs are solenoid-operated, requiring both instrument air and dc power to open. A motor-actuated isolation valve is provided upstream of each of the PORVs to permit isolating the valve for maintenance or in case of failure of the valve to close on demand. The spring-loaded safety valves are totally enclosed and are back pressure compensated. The safety valves are sized to pass sufficient pressurizer steam to limit the primary system pressure to 110% of design (2750 psia) following a complete loss of turbine load without simultaneous reactor trip while operating at 2700 MW(t) even without PORV operation. Since these valves are safety relief valves, there are no isolation valves downstream. Thus in the case of a mechanically failed open safety valve, the break in the system could not be isolated.

Steam discharged from the PORVs and safety valves is cooled and condensed by water in the quench tank. The quench tank is located at a level lower than the pressurizer to ensure that leakage by the valves always flows out of rather than into the pressurizer. The quench tank is maintained with demineralized water. The tank is equipped with temperature, pressure, and level alarms, a rupture disk, and manual fill and drain valves. At 35 psig the quench tank relieves to the waste gas system. At 100 psig, the rupture disk will relieve the tank contents to containment. The tank may also be vented to containment by opening RC-402-SV.

Continuous RCS makeup and letdown flow are provided by the CVCS to maintain reactor coolant chemistry within design limits. Letdown is bled off upstream of a reactor coolant pump on one loop, and makeup is provided by the CVCS charging pumps downstream of a reactor coolant pump on the other loop.

The reactor coolant pumps (RCPs) are vertical, single-suction, centrifugal-type pumps (one pump on each cold leg). Their design flow is 81,200 gpm each. At 95% of full flow, a low reactor coolant flow reactor trip is initiated. The status of the RCPs is very important during overcooling transients. The RCPs add some heat to the system when operating, but also assure adequate mixing and circulation through the warmer core region. Present Calvert Cliffs procedures, however, require that the RCPs be tripped following safety injection actuation signal due to low pressure.

Component cooling water cools the RCP thermal barrier and integral heat exchanger, which cools the shaft seal assembly. The motors are air cooled. A controlled bleedoff flow through the seals is maintained to cool the seals and equalize the pressure drop across each seal. The bleedoff, amounting to about 1 gpm per pump, is collected and processed. On a containment isolation signal, component cooling water to the RCPs is isolated.

The pressurizer, the primary means by which reactor coolant system pressure and coolant volume are maintained, operates at RCS pressure (2250 psia) and saturation temperature (653°F). At full-load nominal conditions, slightly more than one-half of the pressurizer volume is occupied by saturated water. The remaining volume is filled with saturated steam. The steam and water sections are in thermal equilibrium at the saturation temperature corresponding to RCS pressure. Thermal equilibrium is maintained as long as both phases exist. The pressurizer sprays and heaters maintain set-point pressure by either condensing part of the steam (for pressure reduction) or vaporizing part of the water (for pressure increase).

Pressurizer spray water is supplied from both cold legs on the loop containing the pressurizer during normal operation. The water is taken out of the cold legs downstream of the reactor coolant pumps, just prior to entering the reactor vessel (the coolest point) and delivered to the pressurizer spray lines. The automatic spray-control valves in parallel regulate the amount of spray as a function of pressurizer pressure. A small continuous flow of 1.5 gpm is maintained through the spray lines at all time to keep the spray lines and the surge line warm, reducing thermal shock during plant transients. If the reactor coolant pumps are shut down (as will be the case following several transients), the auxiliary spray lines must be used. Water is supplied through the auxiliary spray line by realigning the charging pump discharge from the CVCS.

The pressurizer heaters are single-unit, direct-immersion heaters, 7 ft long, which protrude vertically into the pressurizer through sleeves welded in the lower head. Approximately 20% of the heaters are connected to proportional controllers, which adjust the heat input as required to account for steady state heat losses in the pressurizer.

The remaining heaters, or backup heaters, normally are turned off but are turned on by a low pressurizer pressure signal or high pressurizer level. A low-low pressurizer level signal deenergizes all heaters to prevent heater burnout. The amount of water required to cover the heaters is 266 ft^3.

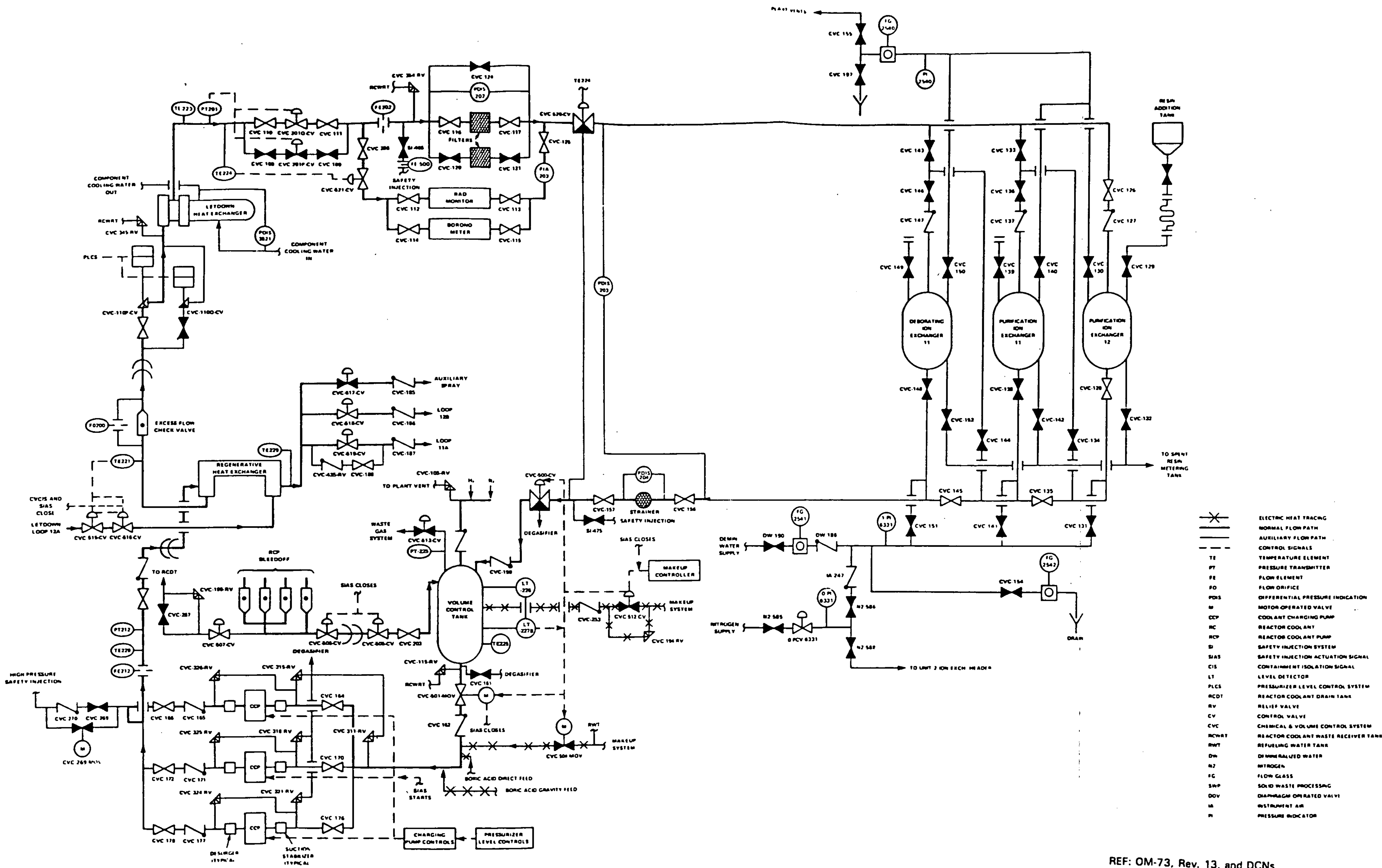
The 96 backup heaters can provide 1200 kW collectively on demand for increased pressure. The maximum spray capacity is 375 gpm, which at a cold leg temperature of 548°F can offset the heat input from the pressurizer backup heaters by almost 4600 kW. Auxiliary spray flow is even colder (395°F) but is limited to 132 gpm, the maximum output of all three charging pumps. The heaters can be operated in manual or in automatic mode. In automatic mode, the heaters are controlled by the pressure regulating system and the pressurizer level regulating system. Pressurizer spray is controlled by the reactor coolant pressure regulating system.

The RCS is also provided with four solenoid-operated vent valves for removal of accumulated non-condensible gas. The reactor vessel and the pressurizer each have two of these valves in series that can be opened manually from the control room and fail shut. The two vent lines join and empty to the quench tank, where gases can be vented to containment via the quench tank solenoid valve RC-402-SV.

B.2 CHEMICAL AND VOLUME CONTROL SYSTEM

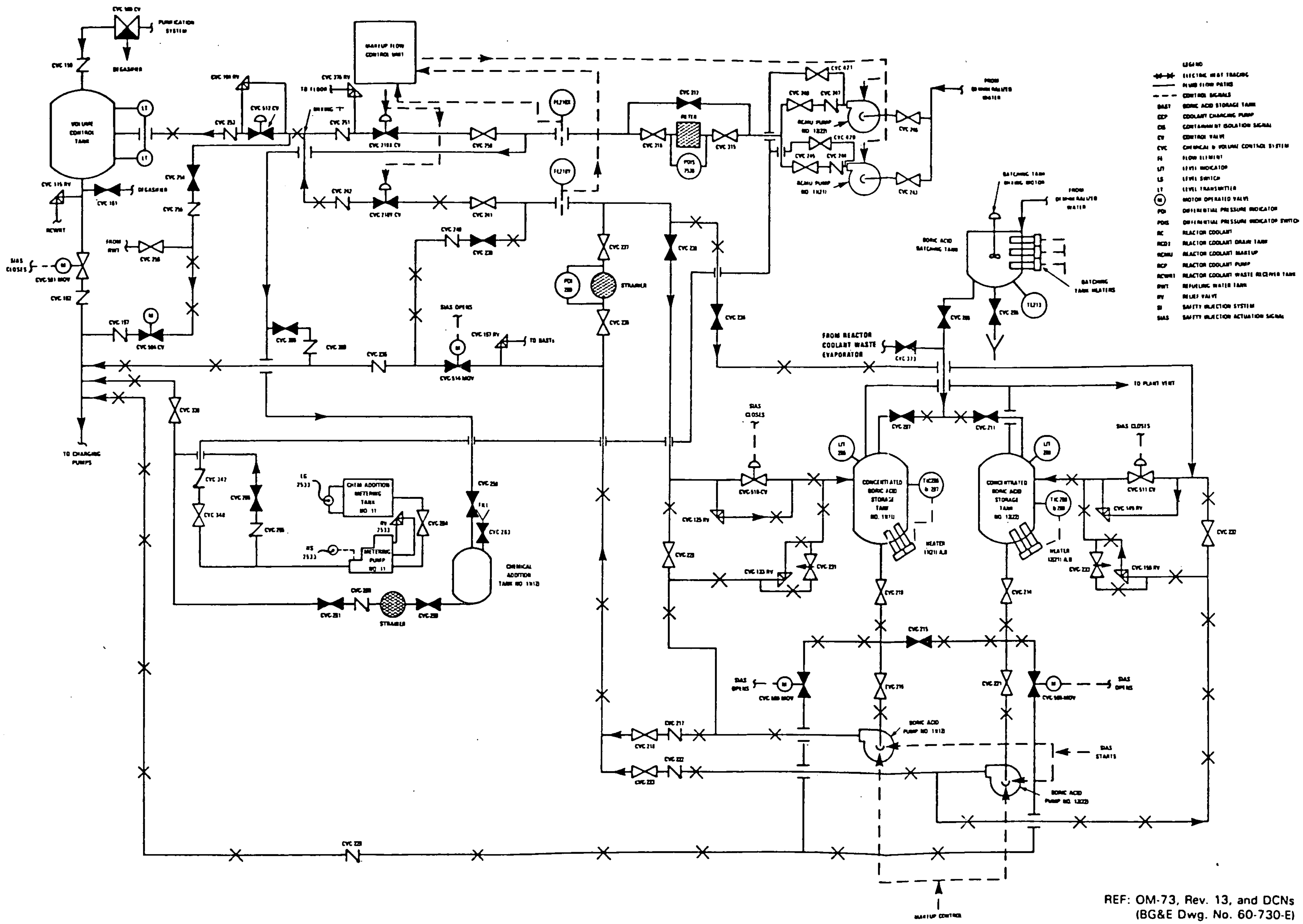
The CVCS is designed to adjust the volume of water in the RCS and to control the chemistry of the water in the RCS by means of chemical addition, removal, and monitoring. The system also injects high head concentrated boric aid into the RCS on a safety injection actuation signal (SIAS). The RCS volume control function compensates for coolant contraction and expansion resulting from changes in reactor coolant temperature and power changes, and for other coolant losses or additions. During normal operation, the chemistry control function maintains reactor coolant activity by removing corrosion and fission products, injects chemicals to minimize corrosion, controls the reactor coolant boric acid concentration, and provides continuous on-line measurement of reactor coolant boron concentration and fission product activity. The description provided here is based on refs. 2 and 3.

The CVCS is shown in Figs. B3 and B4. Reactor coolant normally flows through the CVCS from one reactor coolant cold leg. The coolant is monitored, purified, chemically adjusted, and then returned to the RCS via the charging pumps. The CVCS can be divided into the following subsystems: reactor coolant letdown, purification, volume control, makeup, chemical addition, and charging. The amount of reactor coolant let down from the RCS and returned by the charging pumps to achieve RCS volume control is based on a signal from the pressurizer level



REF: OM-73, Rev. 13, and DCNs
(BG&E Dwg. No. 60-730-E)

Fig. B3. Piping diagram of charging and letdown system.



REF: OM-73, Rev. 13, and DCNs
(BG&E Dwg. No. 60-730-E)

Fig. B4. Piping diagram of makeup system.

regulating system. The pressurizer level set point is programmed to vary linearly with the average reactor coolant temperature. The programmed level set point is maintained in the pressurizer by operation of the CVCS charging pumps and letdown control valves.

RCS letdown from the RCS cold leg passes first through two letdown stop valves in series, the tube side of a regenerative heat exchanger where temperature is reduced from 548°F to approximately 260°F, an excess flow check valve, and then through one of two letdown control valves. The position of the operating letdown control valve (one is in standby) is controlled by the pressurizer level regulating system. The maximum letdown flow rate through each valve is 128 gpm and the minimum is 29 gpm. Next the letdown passes through the letdown heat exchanger, where the temperature is reduced to 120°F, and then through the letdown backpressure regulating valves, which prevent flashing of the hot coolant to steam downstream of the letdown control valves. Backpressure is maintained at 460 psig at the heat exchanger outlet, which maintains liquid instead of steam in the heat exchanger.

The excess flow check valve is installed to minimize the consequences of a CVCS letdown line rupture. The valve is designed to shut at 210 ± 20 gpm, thus limiting the loss of coolant from a downstream pipe rupture (190 to 210 gpm). Letdown is cooled by the cooler charging flow in the regenerative heat exchanger and by component cooling water in the letdown heat exchanger.

The letdown flow next passes through either of two purification filters before it enters the ion exchanger section (purification) of the system. A small amount of the flow bypasses the filters and passes through the boronometer and radiation monitor to measure RCS boron concentration and fission product activity. A temperature control valve upstream of the monitors will isolate to protect the monitors on high letdown heat exchanger outlet temperature (above 145°F). The same temperature indicating controller (TIC-224) will automatically divert high temperature letdown flow from the purification section to the volume control tank (VCT) to protect the ion exchangers from heat damage. Flow is diverted at a 3-way valve, which normally passes letdown flow to the ion exchangers for purification. This valve fails closed to the ion exchangers on loss of instrument air.

The purification subsystem consists of three ion exchangers that can be aligned for series or parallel operation, a downstream strainer, and other support equipment for periodic loading and flushing of resins. Normally, one ion exchanger is in service for purification and the other ion exchangers are placed in service as required for additional purification, coolant deboration, or RCS pH control. High pressure drop across the strainer is measured and alarmed at 20 psid (by PDIS-203).

The letdown flow from the ion exchangers and strainer normally passes through a 3-way, air-operated inlet valve (CVC-500-CV) to the VCT. In automatic mode, the valve directs letdown to the liquid waste processing system if a high level exists in the VCT. This valve fails open to the VCT on loss of air.

Letdown flow entering the VCT enters through a spray nozzle inlet to promote mixture of the reactor coolant with hydrogen in the VCT. A hydrogen blanket of <50 psig is normally maintained in the tank to scavenge oxygen from the coolant and makeup water. The VCT also collects the small offstream from RCP seal leakage. The two valves in series on the RCP seal return fail closed on loss of air. Degasification of combustible and radioactive gases from the reactor coolant is accomplished during maintenance by venting the VCT and purging it with nitrogen. The tank is alarmed for high pressure, which alerts the operator to open the tank vent valve; but the tank relieves automatically only via a relief valve off the normal tank outlet (CVC-115-RV).

Level in the VCT is instrumented to ensure flow supply to the charging pumps. Makeup is normally supplied automatically to the VCT as required to maintain the VCT level within a predefined control band. On low-low level in the tank, the tank outlet valve automatically closes and the makeup valve from the refueling water storage tank (RWT) automatically opens to supply suction flow to the charging pumps. Three level controllers act off the same level transmitter in the VCT (LT-226). One provides normal makeup to the VCT as required (LIC-226), another closes the VCT outlet valve and opens the RWT makeup valve on low-low level (LC-227B), and the third diverts letdown to the waste processing system on high level in the VCT (LC-227A). The valves associated with these controllers also can be operated manually rather than in automatic modes. The VCT is sized to contain enough makeup to maintain pressurizer level (compensate for reactor coolant shrinkage) during a power decrease from full power to zero power).

The charging pumps take suction from the VCT and deliver reactor coolant makeup to the RCS. There are three charging pumps in parallel, with at least one operating and the other two started on demand from the pressurizer level regulating system (on low level in the pressurizer). The pumps are positive-displacement plunger pumps designed to provide a nominal 44 gpm at 2735 psig discharge pressure. The maximum charging flow rate with all three pumps in operation is 132 gpm.

Charging flow passes through the shell side of the regenerative heat exchanger, which transfers heat from the letdown flow to preheat the charging flow from 120°F to approximately 395°F. Charging flow enters the RCS through two reactor coolant loops (11A and 12B) and is also supplied to the pressurizer auxiliary spray during long-term core cooling.

Reactor coolant makeup is normally supplied to the VCT from the concentrated boric acid storage tanks and the demineralized water storage tank. If normal makeup is not available on demand, borated makeup from the RWT is automatically available to the suction of the charging pumps as discussed above. Normally, the boric acid and water supply are mixed upstream of the makeup stop valve (CVC-512-CV) before entering the VCT. The CVCS makeup system also provides the borated water for the RWT on a periodic basis. On a SIAS, concentrated boric acid is supplied directly from the boric acid storage tanks to the charging pump suction header.

The makeup equipment includes two concentrated boric acid storage tanks which feed two boric acid pumps (one in standby), the boric acid batching tank, two reactor coolant makeup pumps for demineralized water supply (one in standby), and associated valves and control. Makeup to the VCT can be operated in any one of four modes: (1) automatic, (2) dilute, (3) borate, and (4) manual. The boric acid concentration in the makeup is set from the makeup flow control unit, which positions control valves on the water and boric acid supply lines. A mode selector switch on the makeup flow control unit determines the makeup operating mode.

The automatic mode is the normal operating mode, with boric acid concentration preset on the flow control unit. When makeup is initiated by a low level in the VCT, one boric acid pump and one reactor coolant makeup pump start, the makeup stop valve (CVC-512-CV) opens, and a blend of makeup is delivered to the VCT. When VCT level is restored to normal, the pumps stop and CVC-512-CV closes.

The borate mode is used to increase the boric acid concentration in the VCT, RWT, or RCS. In this mode, the makeup consists of boric acid and the water supply is shut off. To operate in the borate mode, the desired amount of boric acid addition is set on the control unit, the makeup stop valve (CVC-512-CV) is opened, and the boric acid flow control is set in auto. The amount added is determined by a timer and the flow rate set for the boric acid flow control valve. Switching the mode selector to "borate" starts the boric acid pump and opens the boric acid control valve for the preset time period.

Similarly, the dilute mode is used to decrease the boric acid concentration of makeup to the RCS. In this mode makeup consists of water only and the boric acid supply is shut off. Again, the addition rate and quantity is set, the makeup stop valve (CVC-512-CV) is opened, and the water flow controller is set in "auto." Then, switching the mode selector switch to "dilute" starts one RC makeup pump and opens the water control valve for the preset time period.

The manual mode is similar to the auto mode, supplying a preset blend of water and boric acid to the VCT. In the manual mode, the operator opens the makeup stop valve (CVC-512-CV), starts the boric acid and RC makeup pumps, and runs the pumps for whatever period of time is required--usually based on the level in the VCT. The two control valves (water and boric acid) and the makeup stop valve fail closed on loss of air.

Concentrated boric acid (7.25 wt%) is made up periodically in the boric acid batching tank and added into the boric acid storage tanks. The batching tank capacity is 500 gal, and the storage tank capacities are 9500 gal each. Boric acid also can be supplied to the storage tanks from the reactor coolant waste evaporator. The tanks and all piping that pass boric acid are heated or heat traced to maintain the contents at about 150 to 160°F.

One of two centrifugal boric acid pumps normally supplies the concentrated boric acid to the VCT makeup stream with a recirculating line back to the storage tank. The 143-gpm maximum discharge flow is limited to 30 gpm maximum at the boric acid makeup flow control valve.

The discharge from each boric acid pump is also piped to a common header that can supply boric acid directly to the charging pump suction on a SIAS or during emergency boration. A redundant path for boric acid supply to the charging pump suction header on SIAS that bypasses the pumps is also provided directly from each boric acid storage tank via normally closed gravity feed valves. On a SIAS both boric acid pumps are automatically started, the gravity valves open, the boric acid pump discharge is switched from the VCT makeup to the charging pump suction, the boric acid storage tank recirculating valves and the VCT outlet are closed, and all three charging pumps are started. Seal return to the VCT is also isolated. The emergency boration procedure utilizes this same alignment but requires control room operator action to set it up.

The two RC makeup pumps, which supply the demineralized water to the makeup stream, are also centrifugal pumps with one in standby. These have a maximum capacity of 160 gpm. When a RC makeup pump is energized for "auto" and "manual" makeup, typically the chemical addition metering pump is also started if it is in its normal auto setting.

Normally, chemical addition is a slow, controlled addition at 0.5 to 20 gph from a 100-gal chemical supply tank to the charging pump suction header via the chemical addition metering pump. An alternate path from the metering pump to the RC makeup pump discharge is also provided. For faster chemical addition to the RCS, a small 5-gal chemical addition tank is loaded and flushed to the RCS. This procedure involves aligning the RC makeup pump discharge to the tank and flushing the chemicals through a strainer to the charging pump suction.

In summary the CVCS provides RCS purification and chemical adjustment capability, in the form of monitoring, chemical addition, removal, and hydrogen addition; RCS volume control (letdown, charging, and borated water makeup); boric acid concentration control (boration, dilution, and monitoring); concentrated, high-pressure boric acid injection on SIAS; and other miscellaneous functions not described in detail here, but including RCS degasification, RCP seal bleedoff, auxiliary pressurizer spray; transfer of fluids to the radioactive waste processing system; and a means for leak testing the RCS and selected SI components.

B.3 PRESSURIZER LEVEL REGULATING SYSTEM

The pressurizer level regulating system provides automatic control of the pressurizer level through analog control of the letdown control valve position, start/stop control of the backup charging pumps, and partial on/off control of the pressurizer heaters. There are two letdown control valves in parallel on the letdown line, each of which can pass a maximum of 128 gpm and a minimum of 29 gpm of letdown flow. Under normal operating conditions, one valve is in operation while the other is in closed standby. One of three charging pumps normally operates, delivering 44 gpm of makeup to the RCS. On/off control of the backup charging pumps actuates an additional 44 gpm per pump for a maximum flow of 132 gpm. Charging flow is not throttled but is run back on high pressurizer level by tripping the backup charging pumps. One charging pump continues to operate even on high level unless manually tripped. With all three pumps operating, charging flow supplied to the primary system can develop a high enough pressure to lift the pressurizer PORVs (2385 psig). The pressurizer level regulating system also has dominant control over the pressurizer heaters to turn all heaters full on high pressurizer level and to turn all heaters off on low-low pressurizer level.

Pressurizer level control signals are generated in two separate and fully redundant regulating systems powered separately by vital instrument buses 1Y01 and 1Y02. These systems have separate pressurizer level analog input signals and share the pressurizer level set-point signal developed in the reactor regulating system. The output signals to the operating letdown control valve and to the relays used to control the charging pumps and pressurizer heaters operate from non-vital instrument power (ac Bus 1Y10) and are not redundant.

Failure of vital instrument power to the selected pressurizer level regulating system will produce a zero current demand signal to the letdown control valve and to the backup charging pump control bistables. The letdown valve will close and bistable outputs will de-energize all pressurizer heaters and start the backup charging pumps. These failures can be corrected by manually selecting the alternate pressurizer level regulating system.

Loss of non-vital instrument bus 1Y10 will also provide a zero current demand to close the letdown control valve and de-energize the control relays to de-energize all pressurizer heaters and start the backup charging pumps. The charging pumps, letdown valve, and heaters can be operated in the manual mode through hand stations. A functional block diagram of the pressurizer level regulating system is shown in Fig. B5. Supplemental details of charging pump motor control are shown in Fig. B6.

B.4 REACTOR COOLANT REGULATING SYSTEM

The reactor coolant pressure regulating system controls reactor coolant pressure through automatic control inputs to the pressurizer heaters (1500 kW total capacity) and the pressurizer spray flow control valve (375 gpm maximum flow). A small continuous flow (1.5 gpm) is maintained through the spray lines at all times to keep the spray lines and the purge line warm, reducing thermal shock during plant transients. Reactor coolant pressure is compared to a set-point value (2250 psia), and the error signal provides proportional control of the spray valve position, proportional heater element power, and on/off control of the backup pressurizer heaters. Approximately 20% of the heaters are connected to the proportional controllers, which provide heat input to replace steady state heat losses based on the desired reactor coolant pressure. The remaining backup heaters normally are off but are turned on by a low reactor coolant pressure signal at 2200 psia or high pressurizer level error signal through a bistable controller output.

A high pressurizer pressure signal opens the pressurizer spray valves on a proportional basis, thereby reducing pressure. A low pressurizer pressure signal functions to energize heaters on a proportional or group basis to increase pressure. A high pressurizer level energizes the backup heaters in anticipation of a low-pressure transient; a low pressurizer water level de-energizes all heaters for heater protection.

Two separate and redundant reactor coolant pressure regulating systems are used to develop the pressure control signals. These systems are powered from separate vital instrument buses (1Y01 or 1Y02), and either system can be selected for reactor coolant pressure control through a manual selector switch. Manual control of the heaters and spray may be selected at any time. The pressurizer spray valve control signal and the pressurizer heater demand signal are further processed by modules and relays powered from instrument power on bus 1Y09. Pressurizer heater ac power is obtained through 480-V motor control centers (MCCs 109 PH, 110 PH, 111 PH, and 112 PH). Control modules for the proportional heaters are powered by 480-V Bus 14A.

Each redundant reactor coolant pressure regulating system includes a pressure transmitter, bistable modules to provide independent high and low pressure alarms (2350 and 2100 psia, respectively), a module for control of the proportional heaters, and a control module for on/off control of the backup heaters. Nonredundant components process the

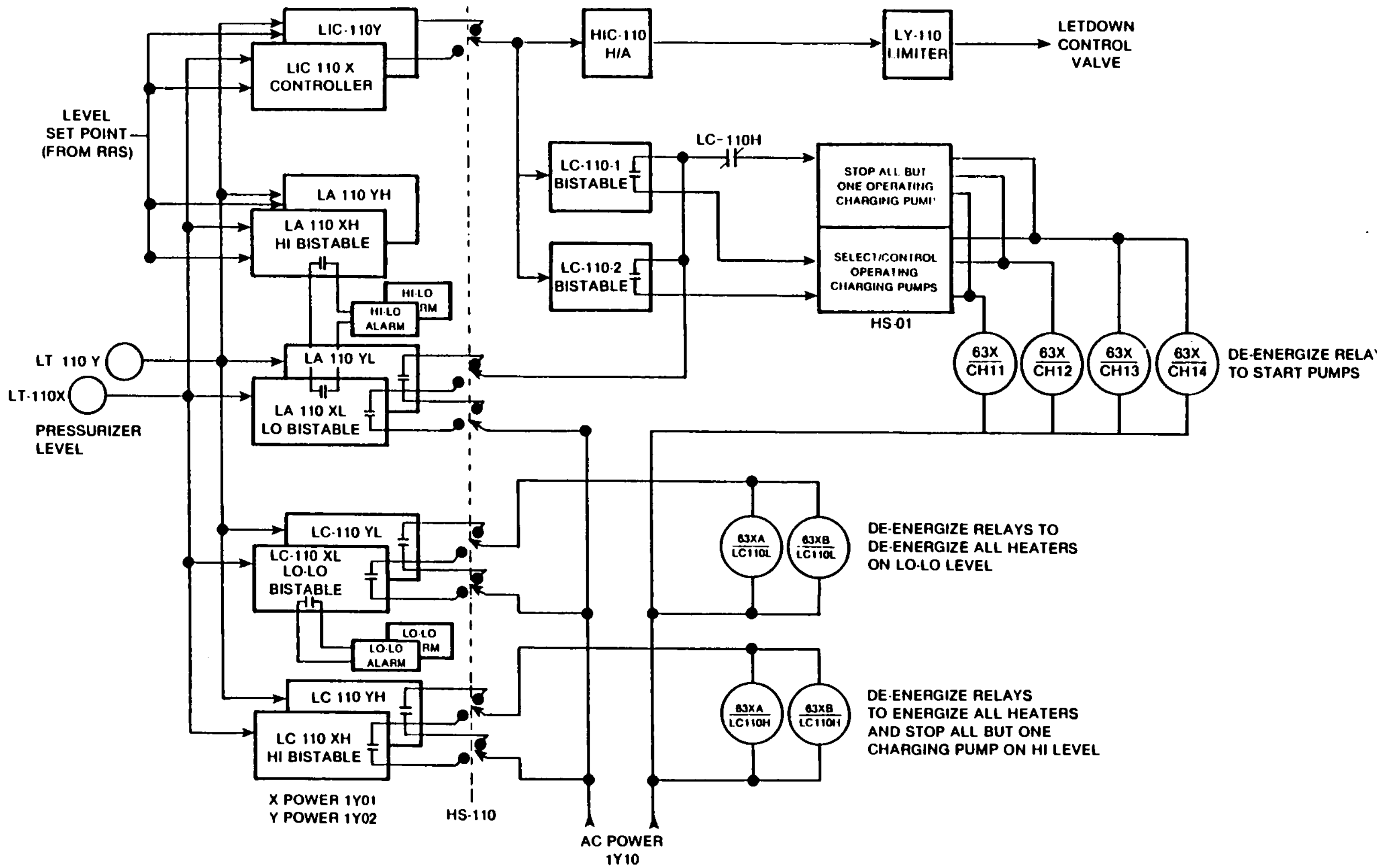
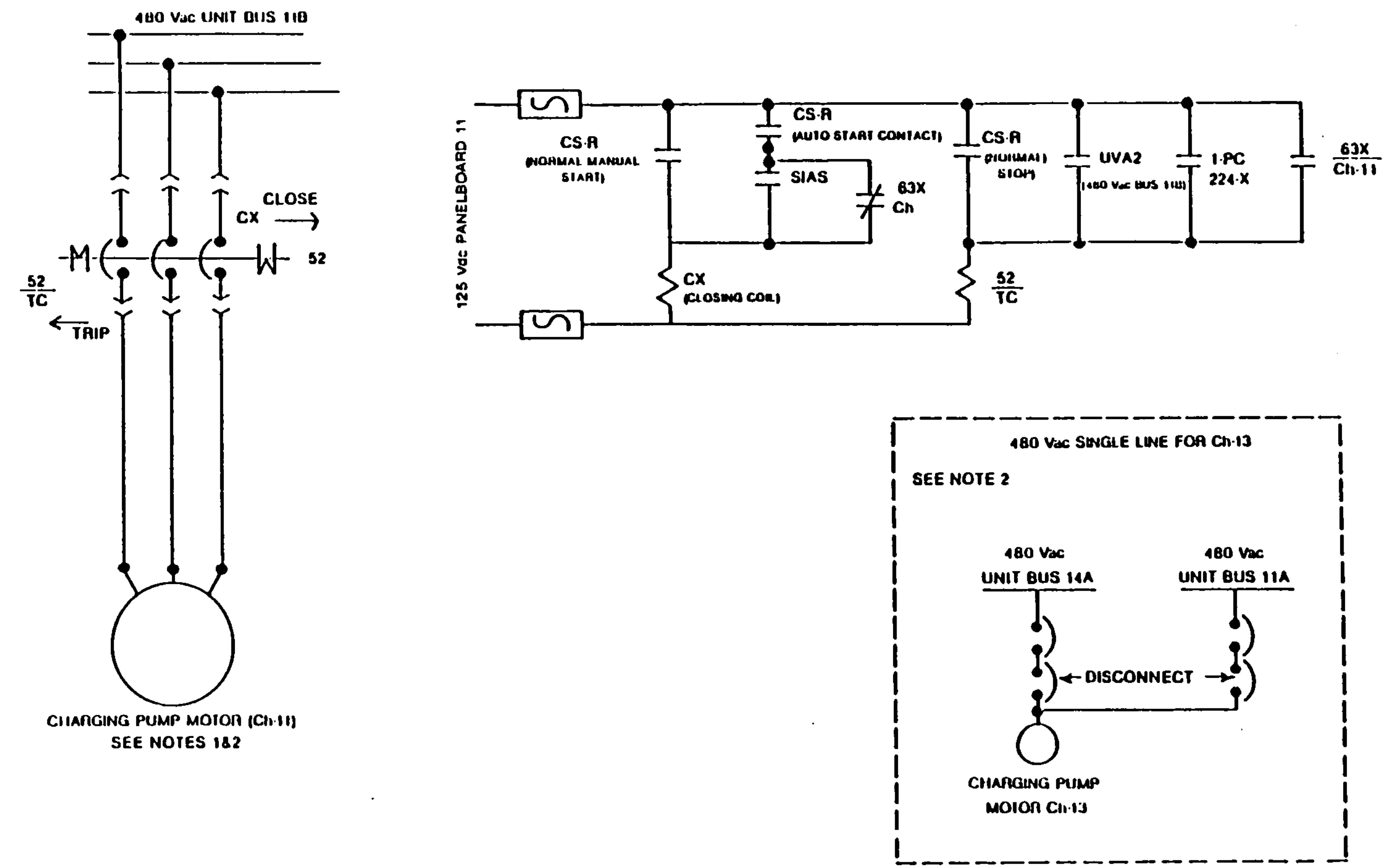


Fig. B5. Pressurizer level regulating system functional block diagram.



NOTE 1 CHARGING PUMP MOTOR (Ch-12) FED FROM 480 Vac BUS 14B; dc PANELBOARD 21
NOTE 2 CHARGING PUMP MOTOR (Ch-13) FED FROM 480 Vac BUS 14A OR 480 Vac BUS 11A VIA MANUAL SWITCH; dc PANELBOARD 11 OR 21

Fig. B6. Charging pump motor control functional block diagram.

heater and spray control signals through relays for on/off control of backup and proportional heaters, and through control modules for proportional control of spray valve position and proportional heater elements. A functional block diagram of the system is shown in Fig. B7.

The pressurizer heater controls include relays in the pressurizer level regulating system and in the pressure regulating system. The pressurizer level relays act to turn all heaters full on at high pressurizer level and to de-energize all heaters on low-low pressurizer level (101 in.). These relays have dominant control over the pressurizer heaters and are powered by pressurizer level regulating system power supplies. Backup heater control details are shown in Fig. B8.

While not formally a part of the reactor coolant pressure regulating system, the pressurizer relief valve contributes to reactor coolant pressure control under certain conditions. A two-out-of-four logic indicating high reactor coolant pressure from the reactor protection system will open the two pressurizer relief valves when the reactor coolant pressure exceeds 2385 psig.

Loss of vital instrument power to the selected reactor coolant pressure regulating system will produce a zero current demand signal to the pressurizer spray valves (the valves will close) and to the heaters (the heaters will energize, unless control is intercepted by the pressurizer level regulating system relays). The pressurizer spray valve and backup heaters can be controlled manually through non-vital instrument power.

Loss of non-vital instrument bus 1Y09 will produce a zero current demand signal to the spray valve I/P (the valves will close) and fail the backup heater control relay in the "off" position.

B.5 REACTOR REGULATING SYSTEM

The purpose of the reactor regulating system (RRS) is to sense the operating condition of the reactor and provide the following information and/or control signals:

- pressurizer level regulating system programmed level set point,
- analog output signal for atmospheric steam dump and turbine bypass valve control,
- total error (power error plus temperature error) signal to provide an

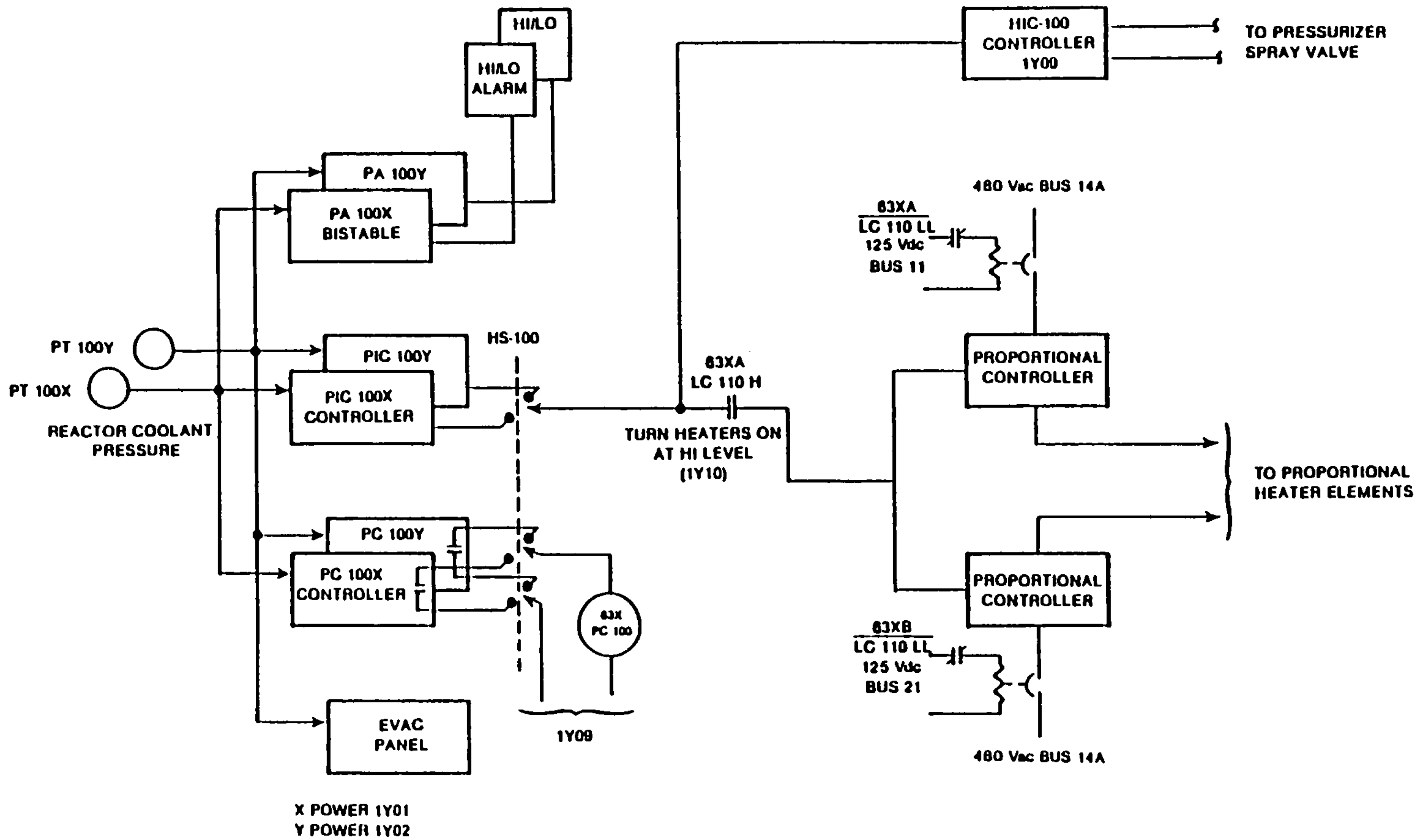
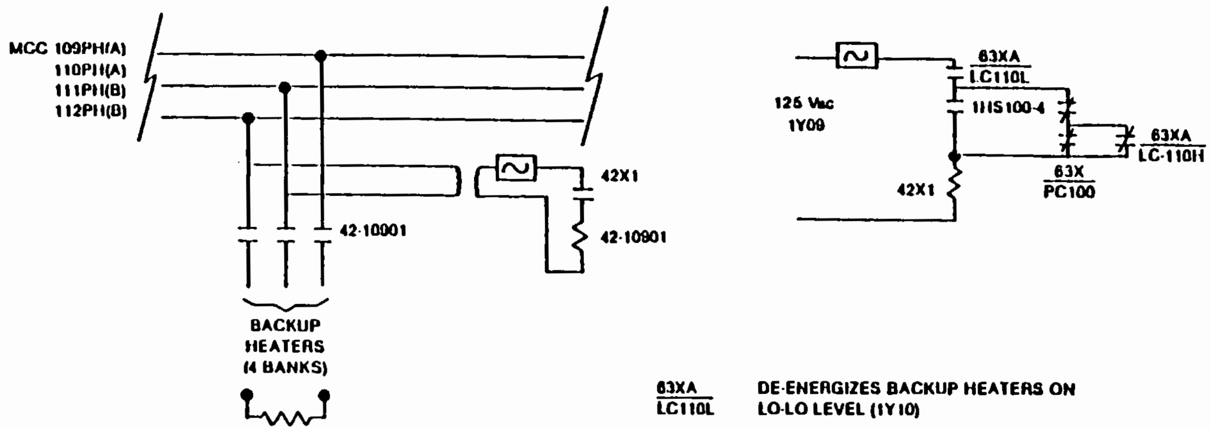


Fig. B7. Reactor coolant pressure regulating system functional block diagram.



63XA / LC110L	DE-ENERGIZES BACKUP HEATERS ON LO-LO LEVEL (1Y10)
63X / PC100	ENERGIZES HEATERS ON LOW PRESSURE (1Y09)
63XA / LC110H	ENERGIZES HEATERS ON HI LEVEL (1Y10)
1HS100-4	HAND SWITCH FOR OPERATOR CONTROL OF BACKUP HEATERS

Fig. B8. Back-up heater control functional block diagram.

automatic control capability for the regulating groups of control element assemblies (CEAs),* and
automatic withdrawal prohibit signal and total error high and low alarms.*

The RRS is left with only two functions, and in that capacity it serves only to provide signal interfaces between other systems. As now utilized, the general system description is as follows:

The RRS, shown in FSAR Fig. 7-11 (Fig. B9) provides control signals which are used to generate a steam dump program and a pressurizer level set-point program.

The RRS is used to provide a signal for pressurizer level set point, steam dump demand, and steam dump quick opening. The operator has the ability to select between redundant systems x or y with a selector switch. Each system is separate and independent of the other. The system functions to give controlling signals as input parameters change. With a change in power level (e.g., an increase), first-stage turbine pressure will follow (i.e., increase) linearly with load. In each channel a temperature programmer establishes the desired reactor coolant average temperature (T_{ref}) based on a power signal from first-stage turbine pressure. This T_{ref} signal is summed with the T_{avg} signal to provide a signal which represents the error between the actual temperature and the programmed temperature (E_t). If the deviation between T_{avg} and T_{ref} should become too high, an alarm will be annunciated. The T_{avg} signal is used to provide a programmed level set point for the pressurizer. The operating level of the pressurizer is programmed to increase with an increase in T_{avg}. This is done to accommodate plant load changes by minimizing changes in reactor coolant system volume during transients.

This T_{avg} signal is also used to provide an analog output for steam dump demand and quick-opening at the time of turbine trip. As T_{avg} increases, the signal to the steam dump control valve increases. This signal is proportional to the quantity (T_{avg} minus 532°F). Should reactor power as determined by T_{avg} be in excess of a predetermined power level prior to a turbine trip, the steam dump quick-opening override bistable will cause quick opening of the steam dump and bypass valves at the time of the trip.

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*The automatic CEA control feature has been disabled at Calvert Cliffs to alleviate regulatory concerns about inadvertent CEA motion and to minimize local power changes in the fuel. The abandonment of the designed function of the RRS as a nominal means of control of the reactor under load through automatic positioning of the CEAs has reduced its safety implications substantially.

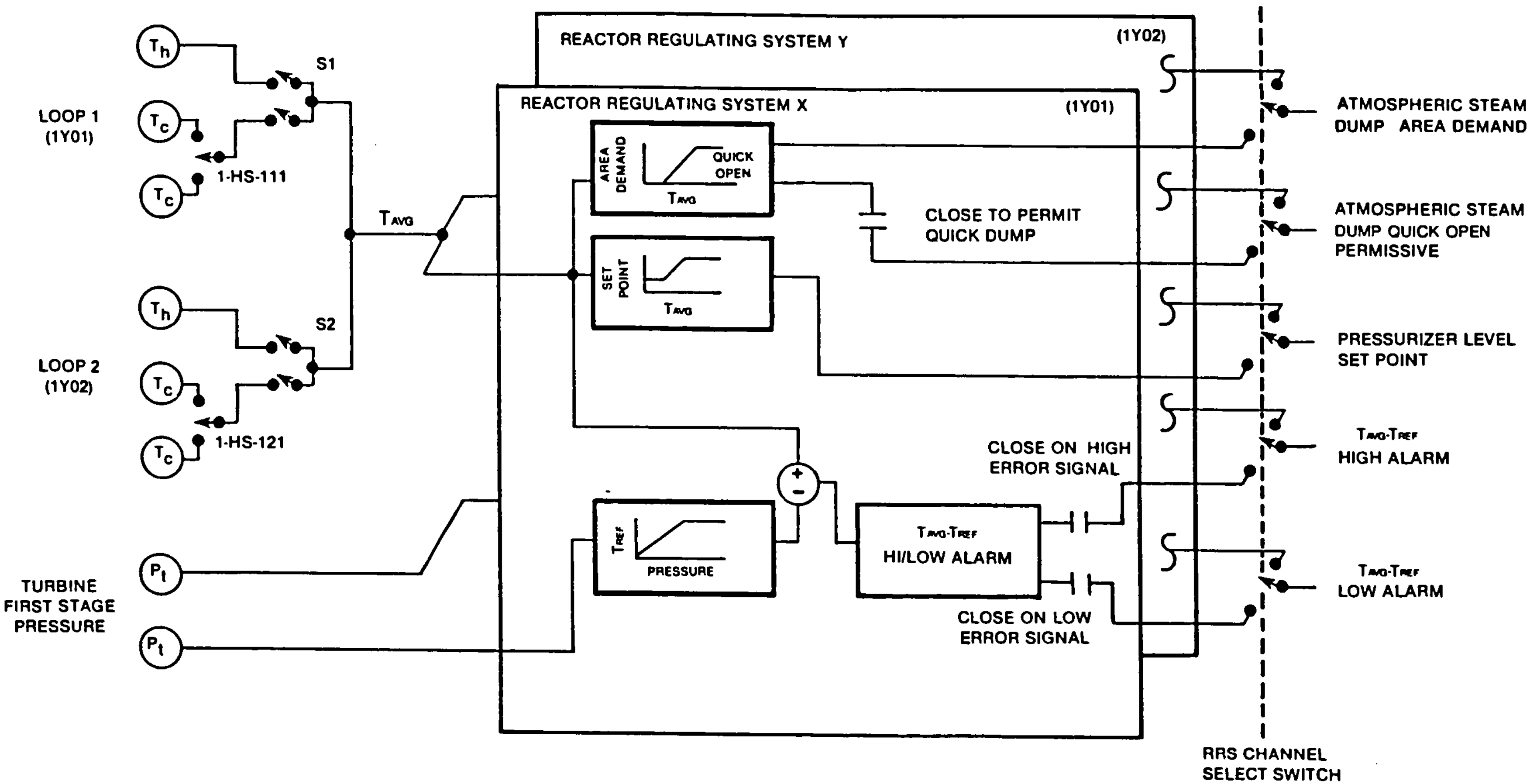


Fig. B9. Reactor regulating system block diagram.

The steam dump program (from RRS) generates a suppressed range signal proportional to the quantity T_{avg} minus 532°F. Upon receipt of a turbine trip signal via the steam dump permissive relay, this signal is supplied to open the atmospheric steam dump valves and is an input to the turbine bypass auctioneering unit to simultaneously open the bypass valves. The position of the atmospheric steam dump and bypass valves is proportional to the signals supplied to them, thus providing a controlled relieving of thermal energy directly relative to the reactor power level.

The atmospheric steam dump valves will close proportionally as T_{avg} decreases and will close completely by 535°F. They will remain closed unless T_{avg} increases again to more than 539°F.

B.5.1 Reactor Regulating System Major Components

This section presents a general description of the RRS major components, signal paths and interrelationships, and interfaces. The purpose of this section is to provide the reader with a general understanding of the system's operation for FMEA purposes. Units 1 and 2 have nearly identical RRS. The following description is based on the Unit 1 system.

Each reactor plant is provided with two independent RRSs. For Unit 1, one RRS provides channel X signals while the other RRS provides channel Y signals. Each RRS is housed in a separate cabinet. The four RRS cabinets are located in panels 1C31 and 1C32 in the control room. Each cabinet contains the four components of the RRS and a power range control channel. The four components of the RRS located within the cabinet are

- reactor regulating system test panel,
- reactor program unit calculator,
- reactor control unit calculator, and
- input/output interface panel.

The power range control channel is physically located within the RRS cabinet. It is however, functionally part of the nuclear instrumentation system (NIS).

Two selector switches are provided for control of input and output RRS signals. Input signals, used by the RRS for output control function signal generation, pass through a function selector switch. An RRS channel selector switch selects which RRS channel (X or Y) provides system output control functions.

B.5.2 Basic Signal Flow Paths and System Interfaces

The basic signal flow paths and system interfaces for the RRS are described in the following paragraphs.

The following signal inputs are utilized by each RRS:

- two hot leg and two cold leg temperature signals (from RCS instrumentation),
- turbine first stage pressure,
- pressurizer pressure, and
- power range neutron flux.

Each RRS is supplied with two cold leg and two hot leg temperature signals from RCS instrumentation.

The signals are in the form of 4- to 20-mA current signals representing 515 to 615°F. These signals are used by the RRS to compute coolant average temperature (T_{avg}). The generated T_{avg} signal is used within the RRS for various output signal calculations. Turbine power level is transmitted to the RRS in the form of a first-stage turbine pressure signal. This is a 4- to 20-mA current signal, which represents 0 to 125% power. The signal is used to compute a reference temperature (T_{ref}) and a power error signal (reactor power minus turbine power) originally designed for use in (no longer connected) CEA automatic control. Pressurizer pressure level is transmitted to the RRS in the form of a 2- to 10-V signal representing a pressure of 1500 to 2500 psia. This signal was designed for use as a stability compensation signal for CEA control. Reactor neutron flux level is transmitted to the RRS by the NIS power range control channel. The control channel transmits a 0 to 10-V signal representing 0 to 200% power. The signal was designed to be used by the RRS as a stability compensation signal for automatic CEA control. The signal is also fed through the RRS input/output interface panel to a two-pen recorder.

The generated T_{avg} signal and the input first-stage turbine pressure, reactor neutron flux, and pressurizer pressure signals pass though the function selector switch. The three-position function selector switch allows testing of the RRS circuits with an internally generated adjustable calibration signal or an externally generated signal. The function selector switch is part of the RRS test panel, which interfaces with each subcomponent and subsystem in the RRS. It is primarily used to test and calibrate the instrumentation in the RRS cabinet. However, it also performs various other functions including calculation of T_{avg} by the RRS test panel summing resistor network.

The following is given as an "as-designed" description for understanding the auto CEA function, which has been disabled. RRS input signals are directed by the function selector switch to the reactor program unit calculator and the reactor control unit calculator. The program calculator functions to produce the following signals:

- pressurizer level set point,

- steam dump valve positioning signal,
- T_{ref}, and
- temperature error (T_{avg} minus T_{ref}).

The pressurizer level set-point signal is transmitted to the pressurizer level controllers in the RCS instrumentation. The steam dump valve positioning signal is sent to the atmospheric steam dump valves and turbine bypass valves to dump steam to the atmosphere and the main condensers on turbine trip, thus removing heat from the primary system. A temperature signal which is proportional to steam demand (T_{ref} program) provides inputs to a T_{avg} and T_{ref} dual-pen recorder and establishes a temperature set-point for manual or automatic CEA control.

A T_{avg} - T_{ref} error signal is calculated and provided to the control calculator to compute CEA motion signals. The error signal is also used to provide a T_{avg} - T_{ref} high/low alarm, an automatic CEA withdrawal prohibit alarm at control room panel 1C05, and an automatic CEA withdrawal prohibit signal to the control element drive system (CEDS). The control calculator computes CEA speed and direction signals.

The RRS-generated output signals pass through a two-position channel selector switch located on control room panel 1C05 that selects which RRS will provide control functions. The switch also interlocks various RRS control functions if the selected RRS is inadvertently placed in test and lights an RRS SELECTED lamp on the selected RRS panel.

An input/output interface panel contains the terminal boards for interconnections of internal and external RRS signals. Additionally, the panel houses the current-to-current (I/I) converters and voltage-to-current (E/I) converters that provide current isolation and output signal interface from the RRS to other systems.

B.6 CONDENSATE, MAIN FEEDWATER, AND STEAM GENERATOR SYSTEM

The condensate and main feedwater system purifies, heats, and pumps the condensate from the condenser hotwells to the two steam generators, completing the steam-feedwater cycle. The condensate and feedwater system is shown on Calvert Cliffs FSAR Fig. 10-4. Simplified schematics of the Condensate and Feedwater System are shown in Figs. B10 through B12.

One condensate pump (8250 gpm) and one condensate booster pump (8540 gpm) are sufficient to provide adequate capacity and discharge head during plant operation at 50% power or less. Above 50% power, two condensate and two condensate booster pumps are necessary to meet condensate requirements. Although a third condensate and condensate booster pump are installed as spares, above 80% all three condensates

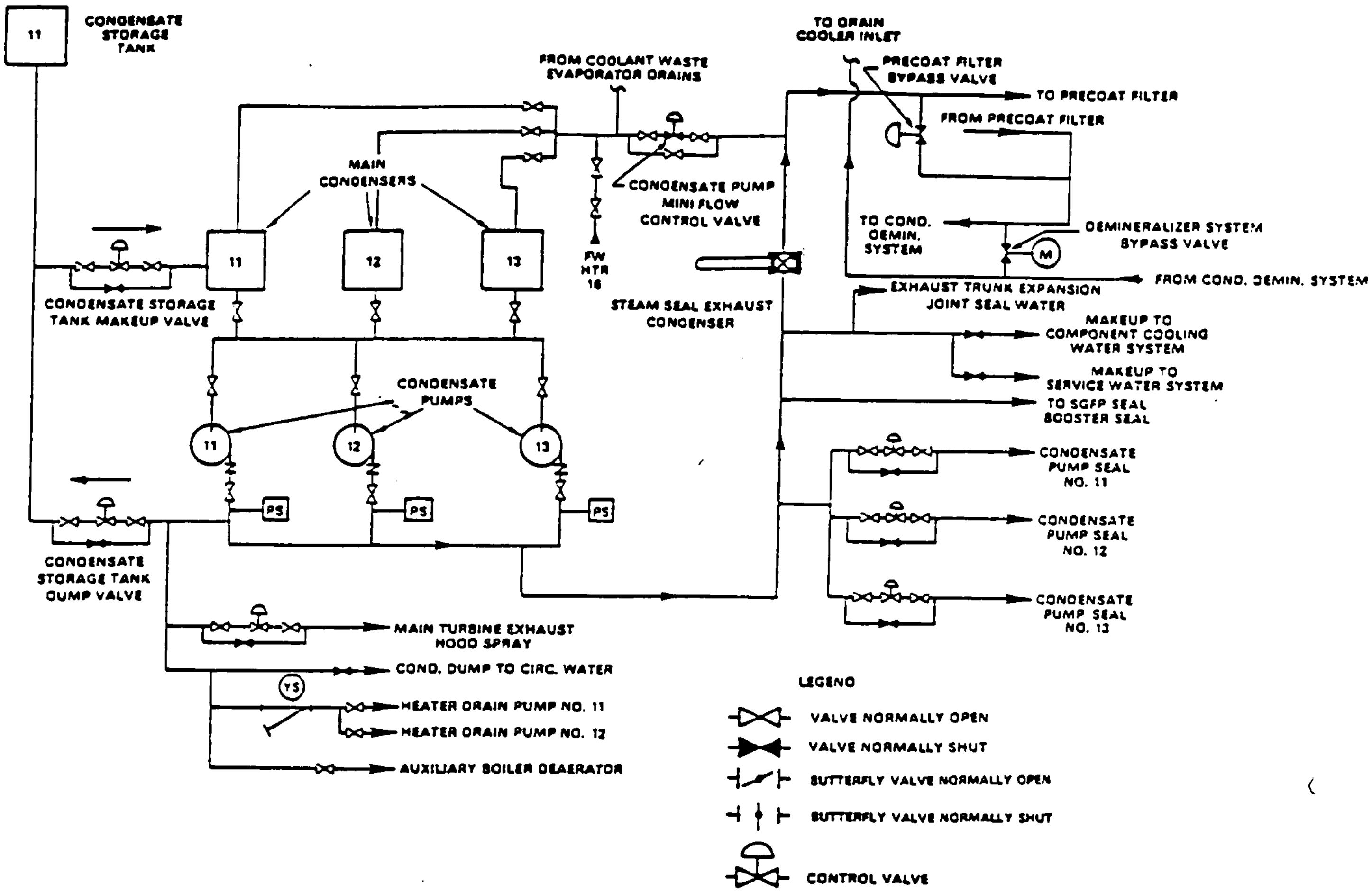


Fig. B10. Unit-1 condensate system simplified diagram (sheet 1).

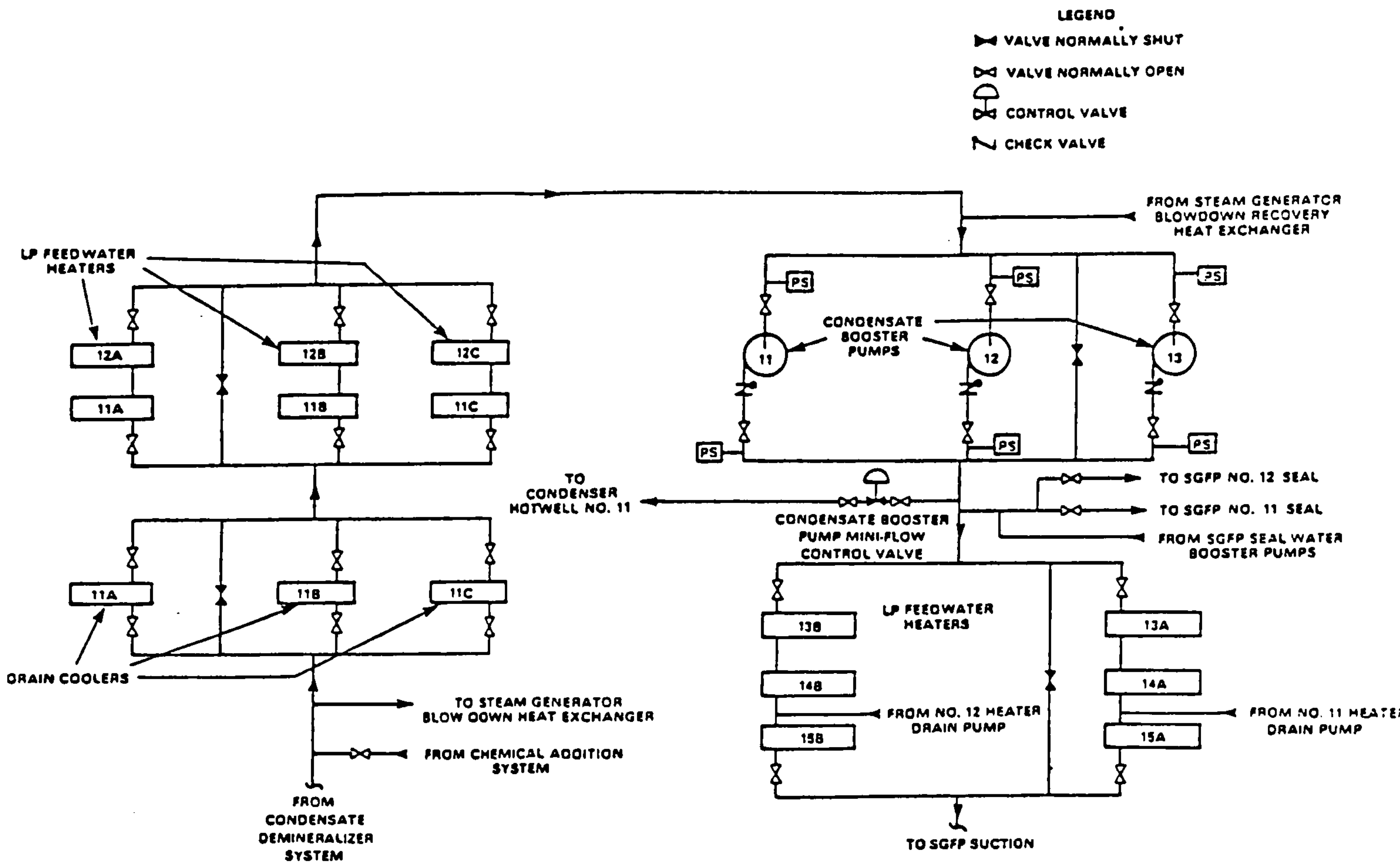


Fig. B11. Unit-1 condensate system simplified diagram (sheet 2).

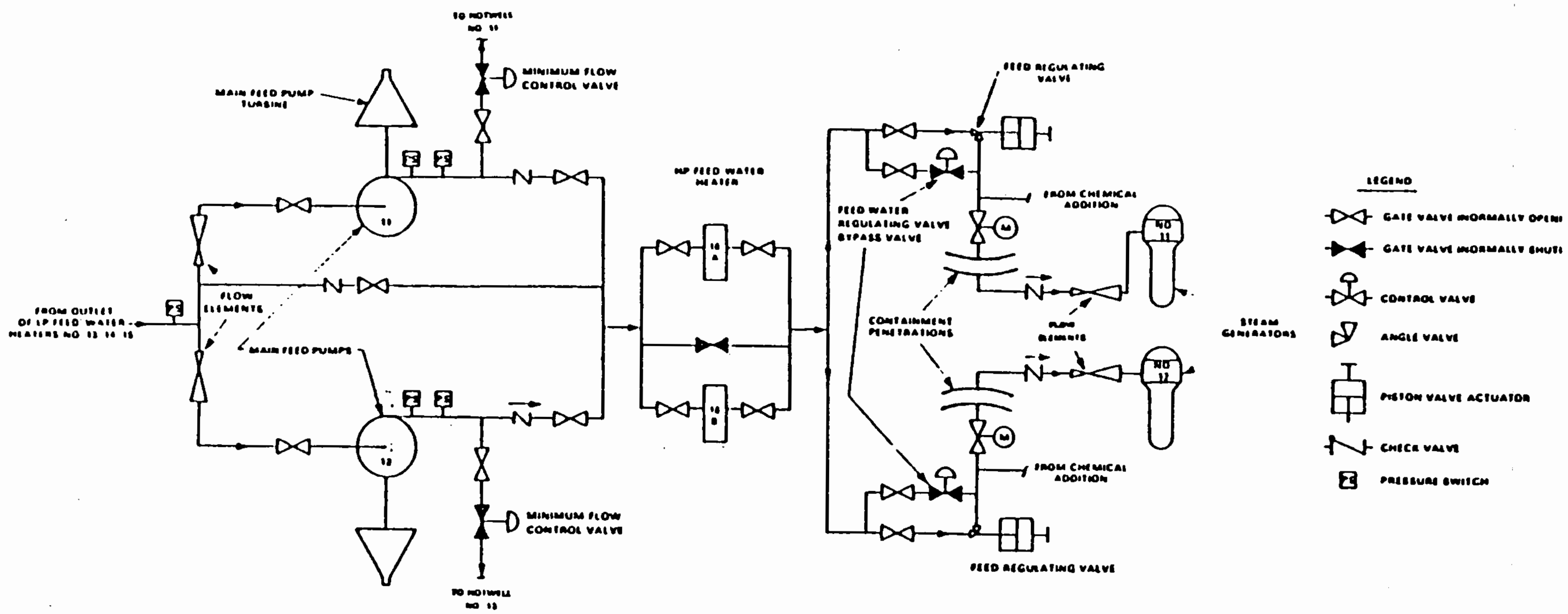


Fig. B12. Main feedwater system simplified block diagram.

and all three condensate booster pumps are operated. The condensate pumps draw condensate from the condenser hotwell and pump it through the steam seal exhaust condenser, precoat filters, demineralizers, drain coolers, and low pressure feedwater heaters to the condensate booster pumps.

Part of the condensate pump discharge flow is diverted for seal water to the condensate pumps and SG feed pumps and for cooling water to the steam generator blowdown heat exchangers. Makeup water may also be supplied from the pump header to the component cooling water system and the service water system. Chemicals including ammonia and hydrazine are added by the chemical addition system to the pump header upstream of the drain coolers to control pH and reduce oxygen concentration.

Condensate is used as a cooling medium in the drain coolers to prevent flashing of the drain water to steam. Three drain coolers are configured in parallel, providing a single stage of drain cooling.

Six low-pressure feedwater heaters, upstream of the condensate booster pumps, are configured with three heaters in parallel, providing two stages of feedwater heating. Extraction steam from the low pressure (LP) turbines is used as a heat source. The heaters are provided to improve thermal efficiency and preclude thermal shocking of the steam generator.

The condensate booster pumps pump the condensate through six more feedwater heaters configured in three stages of two heaters each. Again, extraction steam from the LP turbines is used as the heat source. The condensate enters the steam generator feed pumps after leaving the last stage of feedwater heating.

The condensed steam leaving the feedwater heaters flows to the heater drain tank. The heater drain pumps (4260 gpm) take suction from the drain tanks and pump this water to the condensate system. This water then enters the condensate system upstream of the last low-pressure heating stage (heater stage 15).

Two minimum flow control valves are installed in the condensate subsystem to prevent pump trip during low-flow conditions. The valves are designed to open upon low flow conditions recirculating water back to the condenser hotwell. One control valve is provided on the condensate pump header (8-in.-diam. valve) and the condensate booster pump header (6-in.-diam. valve).

Condensate is also used to cool the main turbine exhaust hood (at low load) and to deaerate the auxiliary boiler.

Upon low level indication in the hotwell, the condensate storage tank makeup valve (CD 4406) is opened, permitting gravity feed of condensate from the storage tank. High hotwell level results in opening of the condensate storage tank dump valve (CD 4405), which permits the pumping of condensate from the hotwell to the storage tank.

The condensate enters the steam generator feed pumps and is pumped through high pressure heaters, feedwater regulating valves, and isolation valves to the steam generators. After the condensate enters the feed pumps it is more appropriately termed feedwater.

The SG feed pumps (15,000 gpm each) are turbine-driven pumps with motive steam supplied by the low pressure reheat steam system during normal operation. The pump turbines use high-pressure steam from the main steam system during startup operations.

Feedwater flows through two parallel high-pressure heaters (heater stage 16) located between the SG feed pump discharge valves and the feedwater regulating valves. Extraction steam from the high-pressure turbine is used to heat the feedwater prior to entry into the steam generators.

The flow of feedwater to the steam generators is controlled by the feedwater regulating valve controller. This controller is controlled during normal operation by a three-element controller, which uses feedwater flow (1FE 1111, 1121), steam flow (1FE 1011, 1021), and downcomer level (1LT 1111, 1121) for level control. Following turbine trip, the regulating valve is closed and the regulating valve bypass valve is opened and controlled by a single element controller that uses downcomer level (1LT 1105, 1106) for control. The regulating valve bypass valve is also used to control steam generator level below 15% power. The speed of the main feed pump turbines is controlled to maintain a fixed differential pressure across the feedwater regulating valves.

A motor-operated isolation valve is provided downstream of the feed regulating valve. This valve permits isolation of the feedwater system in the event of a steam line rupture. Actuation is provided by low steam generator pressure.

A minimum flow control valve (6 in. diam.) is also provided on each SG feed pump to preclude pump trip under low-flow conditions. The control valve recirculates part of the feedwater back to the condenser hotwell.

For information regarding specific details of the condensate and feedwater systems, see refs. 4 and 5.

Steam Generator Description

Each Calvert Cliffs unit contains two identical steam generators. Design information for the steam generator is listed in Table B1.

Table B1. Steam generator design characteristics

	Physical Description
Number	2 per unit
Type	Vertical inverted U-tube
Dimensions	
Overall height (including support skirt)	749 in.
Upper shell	239.75 in.
Lower shell	165 in.
Reactor coolant inlet nozzle	42 in. ID (one each)
Reactor coolant outlet nozzle	30 in. ID (two each)
Main steam nozzle	34 in. ID (one each)
Main feedwater nozzle	18 in. ID (one each)
Auxiliary feedwater nozzle	4 in. ID (one each)
Bottom blowdown nozzle	2 in. ID (one each)
Materials	
Steam generator vessel	Carbon steel
Plenums	304 stainless steel clad
Tubesheet-primry side	Inconel clad
U-tubes	Inconel
Number of tubes	8,519 each generator
Tube size	0.75 in. OD, 0.654 in. ID
Weights	
Dry weight	1.004E6 lbm
Flooded weight at 68°F	1.5267E6 lbs
Volume of secondary fluid	
Secondary side flooded	8006 cubic feet
At normal water level	4592 cubic feet

Table B1. (continued)

	Physical Description
Weight of secondary fluid	
At 0% power	6818 lbs steam 216,284 lbs liquid
At 100% power	9,820 lbs steam 132,975 lbs liquid
Reactor coolant conditions at full load	
Flow rate*	61E6 lbm/hr
Pressure	2250 psia
Inlet temperature	599.4°F
Outlet temperature	548°F
Heat transfer rate	4.386E9 Btu/hr
Steam conditions at full load	
Flow rate*	5.635E6 lbm/hr
Outlet pressure, temp.	850 psia, 525.2°F
Steam quality	0.998 (minimum)
Steam temperature	525.2°F
Feedwater conditions at full load	
Flow rate	5.576E6 lbm/hr
Pressure	1100 psig
Temperature	431.5°F (Unit 1) 435.6°F (Unit 2)

*These flowrates are as reported in the Calvert Cliffs Steam Generator Design Description Number 17, published by Advanced Technology Inc. for Baltimore Gas and Electric Company.

The steam generator is a vertical shell vessel with an inverted U-tube heat exchanger. Primary fluid flows inside the tubes, and secondary fluid flows outside the tubes. The U-tube exchanger contains 5,819 Iconel tubes.

Primary coolant flows from the reactor vessel into the bottom head of the steam generator vessel through the inlet nozzle. A divider plate in the bottom head guides the fluid into the tube bundle and separates the inlet from the outlet primary fluid. The primary fluid leaves the vessel bottom head through two nozzles. When the reactor is at full power, the primary coolant in Unit 1 enters the steam generator at 599.4°F and leaves at 548°F (Unit 2 has slightly different temperatures). The average primary coolant temperature varies linearly from 532°F at zero power to 572.5°F at full power.

The secondary fluid comes from the main feedwater pumps (or the auxiliary feedwater pumps). The feedwater flow enters the steam generator through the feedwater nozzle and is distributed through a circular header ring located 47 in. below the reference operating level of the fluid in the downcomer. The auxiliary feedwater nozzle and distributor ring are located just below the main nozzle and ring. The reference operating level is located near the level of the recirculating fluid sump, which is just below the separators of the steam-water mixture.

Feedwater enters the downcomer through inverted "J" tubes that project upward from the top of the feed ring. The "J" tube prevents the feedwater ring from emptying and causing a waterhammer when refilling with colder water should the liquid level drop below the distributor ring. Feedwater temperature varies with reactor power output and is 212°F at 5% power and 423°F at 100% power.

Feedwater is preheated in the downcomer as it mixes with the recirculated water. The recirculated water is runoff from the steam-water separators located at the bottom of the steam drum and is at the saturation temperature of the steam drum. The ratio of recirculated water to feedwater decreases as the power increases, but the mixed fluid temperature is always subcooled so that boiling and void formation are prevented in the downcomer.

The preheated water leaves the bottom of the downcomer and is directed over the top of the tube sheet and up through the tube bundle, where heat is added to produce saturated water and steam. The quality of the mixture leaving the tube bundle is 0.25 at full power. The steam and water mixture flows upward from the evaporator section through the riser section to the steam-water separators. The saturated water in the riser acts as a surge capacity during transients. The separators are located on a metal support plate at the bottom of the steam drum. The support plate forms a separation between the drum and the riser. The separators have helical vanes that impart a rotational motion to the upward-flowing water mixture, and the centrifugal force effects a separation. The separated water flows outward and downward through holes in the separator outer wall and returns to the downcomer, where it mixes with the cooler incoming feedwater.

The separated steam flows into the steam drum and through corrugated sheet dryers that improve the steam quality to values greater than 0.998. The steam leaves the steam generator through a nozzle located at the top of the vessel and above a deflector plate. The saturated steam temperature leaving the steam drum ranges from 532°F at 0% power to 525°F at 100% power.

The steam generator is designed to maintain a difference between the reactor average temperature and the temperature of the steam produced that varies almost linearly from 10°F to 47.3°F as the reactor power increases from 15% to 100% of full power.

Steam Generator Operating Principles

The Calvert Cliffs steam generators are designed with sufficient surge capacity for the secondary-side steam and water to respond to the power transients that are expected in the startup and shutdown of a base load operating plant. The internal flow is maintained by natural circulation. The liquid level is normally maintained by an automatic control system that adjusts the feedwater flow. The plan is also protected through high and low level trips.

The natural circulation path in the steam generator includes the downcomer, the shell side of the heat exchanger, the riser section above the tube bundle, and the separators. The free surface of the flow path includes that of the downcomer and the recirculated water return path to the downcomer. The water at this surface is at the bottom of the steam drum and is in thermal equilibrium with the steam in the drum. The reference zero level for the liquid level and feedwater flow control system is located near the bottom of the recirculating water collection sump that supplies water to the downcomer.

The driving force for the flow around the natural circulation loop is supplied by the net density difference between the fluid in the downcomer and the fluid in the remainder of the loop. The driving force required to maintain steady state increases as the reactor power and the steam generation rate increase. The increased driving force is obtained from a decrease in the density on the upflow side of the circulation loop as steam bubbles are produced in the boiling water.

The resistance to the flow is the sum of the friction and acceleration forces generated as the water and steam flow through the entire circuit, including the downcomer, tube bundle, riser and separators. Flow resistance varies roughly as the sum of the terms involving squares of the velocity of the fluid in the downcomer and the riser, and of a term which involves differences of the squares of the velocities of accelerated fluid. As the void fraction increases on the riser side, the recirculating water flow around the loop starts to decrease. The mass velocity in the natural circulation loop increases to a maximum value at about 70% of full power and decreases about 5% between 70 and 100% of full power. The riser circulation rate is constant within ±3% when the power ranges between 50% and 100%.

Steam Generator Control

The feedwater control system is designed to maintain a fixed level in the downcomer. Feedwater flow is controlled primarily by modulating the main feedwater control valve and secondarily by controlling the speed of the feedwater pump. The main feedwater control valve has two modes of control, which depend upon the power level. The modes are switched at 15% power.

Below 15%, power the flow control signal is based on a proportional band (i.e., a fixed gain) determined from the level error, which is determined by the difference between the measured level and a set point.

Above 15% power, feedwater flow control is based on both the level error and the difference between the feedwater and steam flows. The controlling signal consists of the proportional band and the time integral of the level error, plus a proportional band signal using the difference between the steam flow and the feedwater flow.

Secondary control of feedwater flow is obtained by varying the speed of the feedwater pump. This control system uses the pressure drop across both feedwater valves as inputs. The smaller pressure drop signal is compared to a set point of 105 psid, and the difference is sent to a controller. The controller generates a speed control signal based upon the derivative, proportional band, and time integral of the pressure difference error. The direction of control is such that the speed of the pump will be increased when the smaller pressure drop is below the 105 psid set point.

The steam pressure and flow rate at the header of the first turbine stage are controlled manually from the turbine-generator control system. (The Calvert Cliffs plant is a baseloaded plant.) To establish the steam generator operating conditions when the desired operating power level is determined, the turbine-generator operator controls the setting of the turbine steam inlet valve to achieve a programmed pressure and steam flow rate for the desired electric power level. The reactor operator adjusts the positions of the reactor control rods and the boron concentration in the primary coolant (with the chemical addition system) until the average coolant temperature (T_{avg}) is increased to generate the required steam flow rate and steam pressure at the turbine steam inlet valve.

Steam Generator Safety and Protection System

In addition to the control system, the stem generator has safety limits that will either cause a turbine trip on high downcomer water level or a reactor trip on low level (see Table B2). The level measurement used in the safety system consists of four ΔP instruments that generate a signal that can be used to infer a liquid level in the downcomer. These four

Table B2. Summary of significant steam generator levels

	Distance Above Normal Operating Level (in.)
High high-level turbine trip	+50
High level alarm	+30
Normal operating level (550 in. above baseplate)	0
Low level alarm	-24
Low low-level reactor trip	-46.8
Main feed ring	-47
Top of tube bundle	-55
Auxiliary feed ring	-59
Low-level auxiliary feed actuation signal	-170
Bottom of tubesheet	-412.2

signals are sent to a two-out-of-four logic device, which can generate a trip when the safety limits are exceeded. The high-level turbine trip is part of the engineered safety features actuation system (ESFAS). Two-out-of-four logic is used to prevent false trips, ensure valid trips, and allow for on-line testing. This logic system, however, reduces to one element that generates the trip signal (i.e., a single OR gate actuates a single relay which causes the turbine trip). If either of these devices, the OR gate or the relay, is in an undetected failed state, the turbine trip signal will not be generated from this circuit.

The same condition exists for the reactor trip on low water level, which uses a two-out-of-four logic and has a single OR gate and a single relay to generate the trip signal. If either the OR gate or the relay is in the undetected failed state, reactor trip will not be generated.

The steam generators are protected from overpressure by a set of eight safety valves, all of which can exhaust steam to the atmosphere. In addition there is a flow-restricted venturi that limits the blowdown rate of the generator in case of a steam line rupture inside the reactor containment and upstream of the main steam isolation valves. Flow is limited to prevent an excessive buildup of pressure in the containment vessel in case of an accident. These protection devices do not require any action by the control system, and there is no action that the control system can take to stop the safety action of the valves if the set points are exceeded. The safety valves can relieve 103.79% of the full power steam capacity at a steam header pressure of 1035 psig.

In addition to these safety systems, an atmospheric blowdown line and turbine bypass valves to the main condensers are used to reduce challenges to the safety valves and to limit the pressure in the steam generator in case of a reactor trip.

Turbine bypass valves allow steam to flow directly from the steam generator to the main turbine condenser without going through the turbine. The capacity of each turbine bypass valve is 10% of the steam produced at 100% power. This valve is installed to allow the steam generator to dump its steam inventory (to the main condenser) without opening the safety valves when a turbine trip occurs. It is also sufficient to allow condensation of the steam generated from decay heat without exceeding normal operating pressure.

The atmospheric dump valve allows the steam generator to dump steam to the atmosphere when the turbine and main condensers are not operating. The atmospheric dump valve line entrance is located upstream of the main steam isolation valve (MSIV), so pressure in the steam generator is isolated from the rest of the reactor plant.

Each steam generator has separate isolation valves on both the main feedwater and auxiliary feedwater lines. This enables a single steam generator to be isolated from either or both feedwater flow headers.

The auxiliary feedwater (AFW) system has two steam turbine-driven pumps (one of which is isolated from the loop by a hand valve) and an electric motor-driven pump. The steam-driven pump has dc-powered controls. If there is a power failure, the plant protection system will start one steam-driven AFW pump after the reactor and turbine are tripped. If there is a turbine and reactor trip with offsite power available, the motor-driven pump will be activated. These control systems are safety grade.

The lowest level (-170 in.) steam generator alarm will activate the auxiliary feedwater actuation system (AFAS). The AFAS will start the AFW pumps and, after an appropriate time delay, run back the main feedwater (MFW) pumps and close the motor-operated valves that isolate both of the steam generators from the MFW system. This procedure assures continued availability of the MFW flow while avoiding the possibility of emptying the pressurizer by overcooling the primary system. After an additional preset time delay, the equipment will remain in its actuated condition regardless of the steam generator level until the operator resets the AFAS at the AFAS cabinets or from the control room.

There are AFAS "block" signals provided for each steam generator. If a low steam generator level is detected and, in addition, there is a high differential pressure between the steam generators' secondary sides, two blocking signals will be generated. Each blocking signal will shut one of the two blocking valves in each of the steam-driven and motor-driven pumps' discharge lines to the indicated leaking steam generator. This block makes the AFW unavailable to that steam generator as long as the initiating conditions for the block exist. When this block is present, the AFAS will not run back the main feedwater pumps.

B.7 FEEDWATER REGULATING SYSTEM

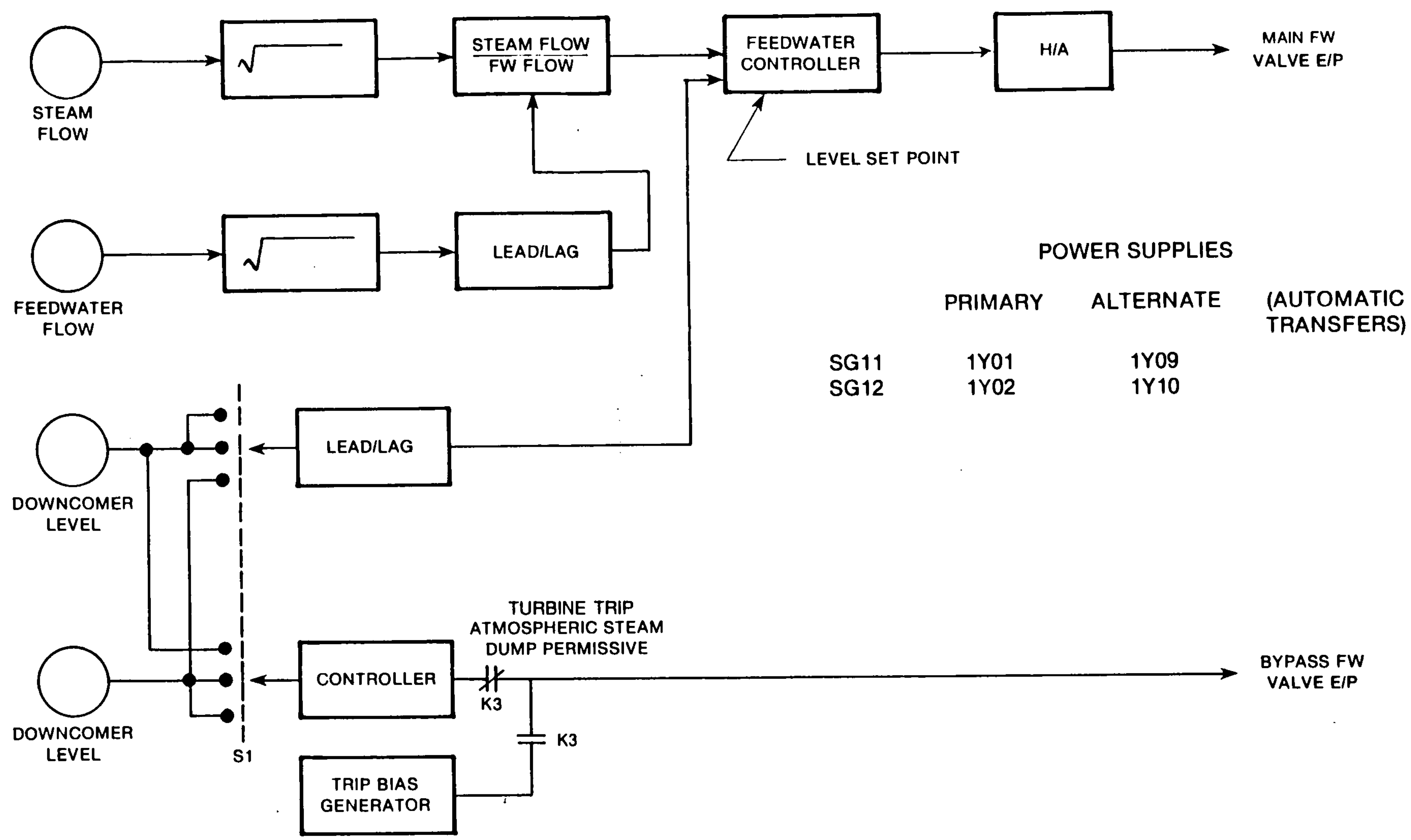
Calvert Cliffs has two fully separate feedwater regulating systems. (A block diagram of the feedwater regulating system is shown in Fig. B13). Each system controls the main and bypass feedwater valve for one steam generator. Each steam generator level is compared to a set point and modified by the ratio of steam flow to feedwater flow to adjust the regulating valve. The main feedwater valves are automatically closed and the bypass valves set to 5% flow following reactor trip. This position can be overridden manually by the operator.

The feedwater regulating system receives primary ac power from separate vital buses 1Y01 and 1Y02. Upon loss of an associated vital bus, the feedwater regulating systems automatically transfers to separate non-vital instrument buses 1Y09 and 1Y10. One vital bus and the associated non-vital bus must be lost before one feedwater regulating system is compromised, and both vital buses and both non-vital buses must be lost before both feedwater regulating systems are compromised.

The main feedwater valve electric-to-pneumatic (E/P) position controllers have solenoid valves on the air lines that use non-vital instrument power. Each of the two main feedwater valves has a different source of instrument power. Loss of non-vital instrument power will fail the affected main feedwater valve position "as is."

The three-element main feedwater valve controller (FC1111, 1121) receives inputs of steam flow (FT1011, 1021), feedwater flow (FT1111, 1121), and steam generator downcomer level (LT1111, 1121 or LT1105, 1106). Steam and feedwater flows are provided to a comparator (FY1112, 1122) prior to processing by the feedwater controller. The steam and feedwater flow signals are summed in the comparator to produce an error signal. The downcomer level is provided to a lead/lag unit prior to processing by the controller. The lead/lag unit reflects transients in the steam generator level. The level signal is summed with the steam/feed flow error signal to produce a final signal to control the feedwater valve. A steam generator level set point, which is consistent with plant power level, is generated in controller FIC1111, 1121 and fed into controller FC1111, 1121. The final signal fed to the steam generator feedwater regulating valve controller adjusts the regulating valve to attain the correct level in the steam generator.

Differential pressure transmitters sense the pressure drop across the feedwater regulating valves and send signals to the feedwater regulating valve differential pressure controllers (PDIC 4516, 4517). These



POWER SUPPLIES

	PRIMARY	ALTERNATE	(AUTOMATIC TRANSFERS)
SG11	1Y01	1Y09	
SG12	1Y02	1Y10	

Fig. B13. Feedwater regulating system.

controllers are set to maintain a 105-psig differential pressure across the feedwater regulating valves. The controllers send error correction signals to control feedwater pump turbine speed when the feed pump turbine is in the automatic control mode. As power level and valve position change, the correct feedwater differential pressure will be maintained to ensure flow into the steam generators.

The three-element feedwater control system is used to control steam generator level at power levels above 15%. At power levels below 15% or upon turbine or reactor trip, the single-element feedwater control system is used to control the level. The single-element control system regulates the feedwater regulating bypass valve to control the level in the steam generator. Below 15% power, steam generator shrink and swell effects are not present to give false indication of steam generator level. A steam generator level signal is generated by LT1105, 1106 or LT1111, 1121. This signal is sent to the feedwater bypass valve controller (LIC1105, 1106) where the actual steam generator downcomer level is compared with a level set point to produce an output signal that is converted into a pneumatic signal, which operates the feedwater bypass valve.

For additional details regarding operation of the feedwater regulating system, see ref. 4.

B.8 MAIN STEAM AND ATMOSPHERIC STEAM DUMP-TURBINE BYPASS CONTROL SYSTEM

The main steam system transfers steam from the steam generators to the following equipment:

- main high pressure (HP) turbines,
- moisture separator reheaters,
- main steam generator feedwater pump turbines,
- auxiliary feedwater pump turbines, and
- steam seal regulator.

A simplified schematic of the main steam system is shown in Fig. B14. The atmospheric steam dump and turbine bypass control system functional block diagram is shown in Fig. B15. The main steam system also provides overpressure protection for the steam generators by relieving excess pressure to the atmosphere or the condenser. Automatic removal of nuclear steam supply system stored energy and sensible heat is provided by the main steam system following a turbine and reactor trip.

B.8.1 Main Steam Flow Path

During normal plant operation, steam generated in the steam generators flows through a main steam header to the main high-pressure turbine stop valves. Each main steam header has a flow restrictor and a main steam isolation valve (MSIV). The two main steam headers from the steam

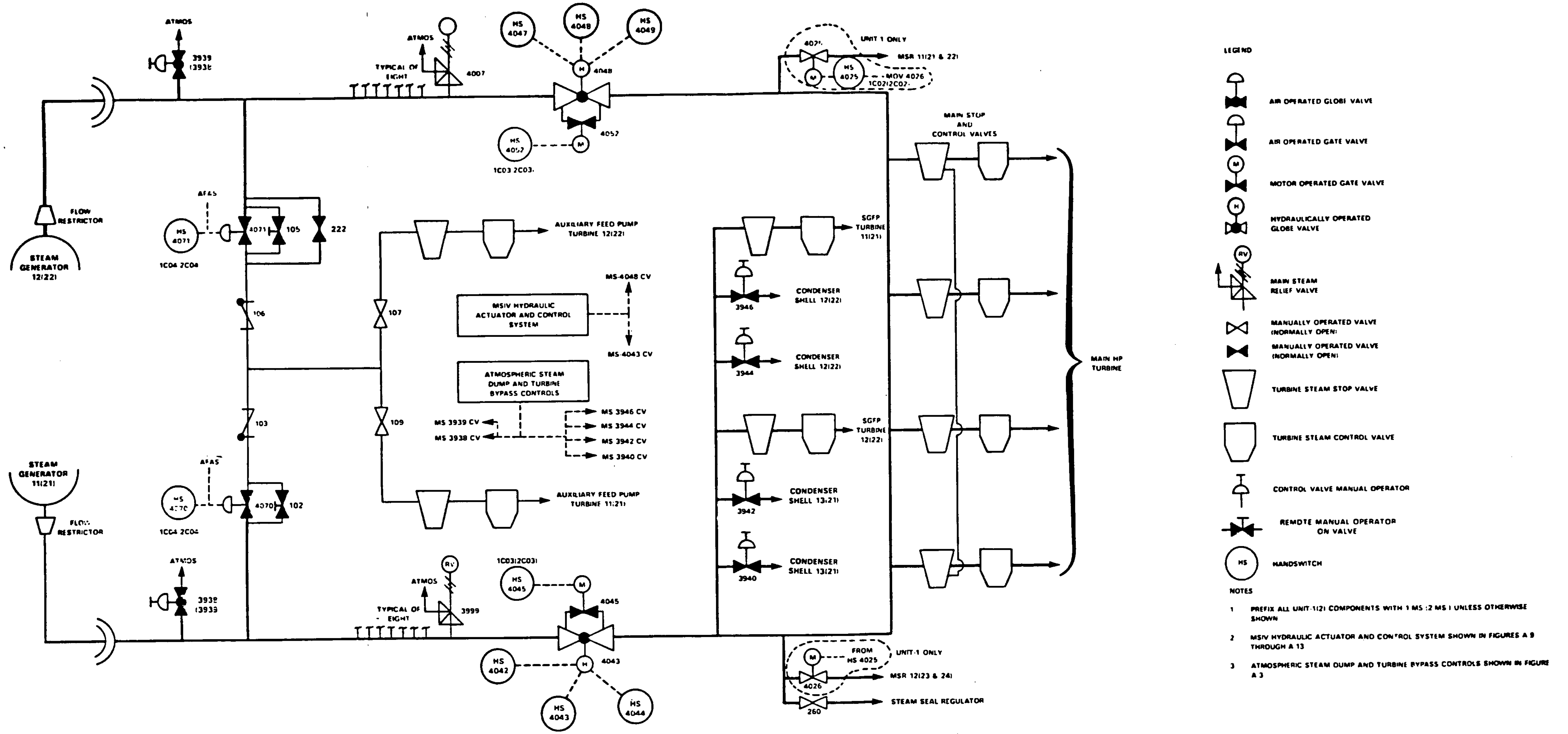


Fig. B14. Main steam system flow diagram.

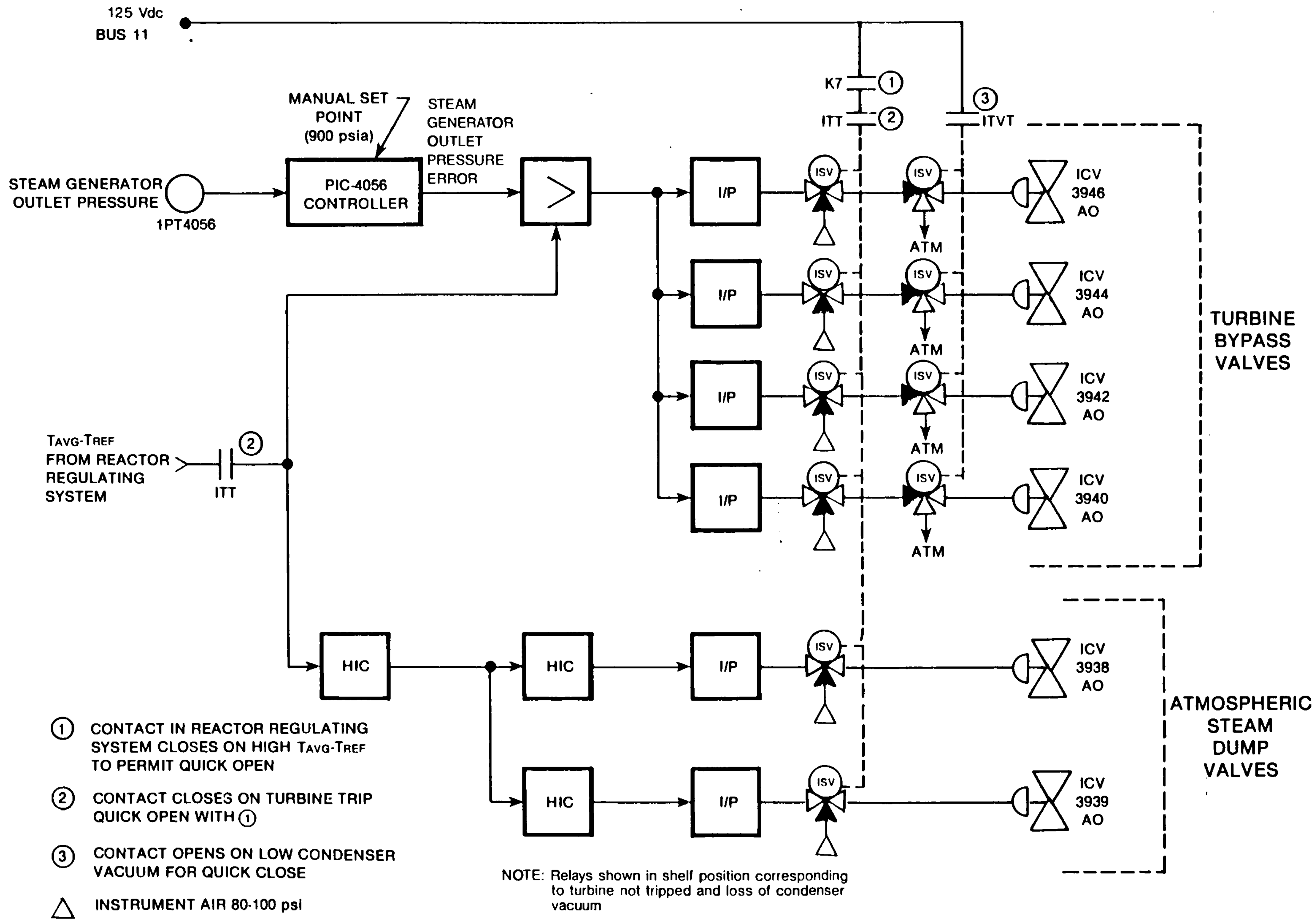


Fig. B15. Turbine bypass and atmospheric steam dump functional block diagram.

generators are cross-connected downstream of the MSIVs. Steam from each main steam header flows through air-operated control valves to the auxiliary feedwater pump turbines. A smaller diameter branch header provides a steam flow path to the moisture separator reheaters and to the steam seal regulator. Another branch header, connected to the main steam header, supplies steam flow to the main steam generator feedwater pumps.

Each main steam header is provided with one atmospheric steam dump and eight ASME-code safety relief valves, which are connected between the containment penetration and the MSIV. These valves, normally shut, are opened to exhaust main steam to the atmosphere. Four turbine bypass valves are connected to the same branch header that supplies the main steam generator feedwater pump turbines. These valves, which are normally shut, are opened to exhaust steam to the main condenser.

B.8.2 Main Steam Components

Immediately downstream of each steam generator outlet nozzle is a venturi flow restrictor. The flow restrictor serves to limit the main steam flow rate in the event of main steam header rupture. Each flow restrictor is designed to limit steam flow to approximately 170% of normal flow. These components are designed to withstand a maximum pressure and temperature of 1000 psia and 580°F.

Overpressure protection for the secondary side of the steam generators and main steam header up to the inlet of the turbine stop valves is provided by 16 spring-loaded ASME-code safety valves. The safety valves are set to open sequentially, two at a time, when header pressure exceeds and continues to rise above 985 psig. When all eight safety valves on one main steam header are open simultaneously, these valves are capable of relieving approximately 104% of the steam flow from one steam generator.

A hydraulically operated MSIV is installed in each main steam header between the code safety valves and the turbine stop valves. These Y-pattern globe valves are capable of withstanding steam pressure and temperature of 1085 psia and 580°F. The MSIVs are capable of shutting against 1000 psig of steam pressure applied to the valve seat.

The MSIVs are installed to protect the steam generator and the reactor from damage due to a rupture in the main steam header. The valves are designed to close within 6 s of a SGIS. Quick closure prevents rapid flashing and blowdown of steam generator water due to steam flow through the rupture. Rapid removal of steam from the steam generator could cause rapid cooldown of the reactor coolant. The SGIS is generated when the steam pressure in the steam generator drops below 653 psia. A blocking signal is necessary to block the SGIS actuation during normal shutdown from power operation.

The atmospheric steam dump and turbine bypass system is used to remove stored energy and sensible heat following a turbine and reactor trip. This system is used to control secondary steam flow so that the safety valves are not frequently challenged. It can handle 45% of total secondary steam flow. The atmospheric dump and turbine bypass system comprises two atmospheric steam dump valves and four turbine bypass valves.

The atmospheric steam dump valves are connected to the main steam header between the containment penetration and the code safety valves. When opened, both dump valves exhaust up to 5% of the total steam flow from the steam generators.

The dump valves are designed to withstand a maximum steam pressure and temperature of 1000 psig and 580°F. These valves fail shut and are equipped with a chain operator, which permits manual override. These valves are designed to quick open at reactor power levels above 63% to remove steam flow from the steam generators.

Four normally shut turbine bypass valves are connected to the steam generator feedwater pump supply header downstream of MSIV 11. The turbine bypass valves are air-operated, 10-in. globe valves fabricated of carbon steel. When opened, the four valves are capable of passing 40% of the total secondary steam flow to the condenser. These valves are designed to withstand a maximum steam pressure and temperature of 1000 psig and 580°F. The valve operators are equipped with handwheels to permit manual operation should their controls fail to operate. When the main turbine trips while the reactor is operating above 63% power, the turbine bypass valves receive a quick-opening signal from the main turbine control system. If the main steam pressure exceeds 895 psia without turbine trip, the bypass valves are opened automatically.

The atmospheric steam dump and turbine bypass controls provide automatic or manual control of the atmospheric steam dump and turbine bypass valves during normal and emergency plant operation. During normal operation, the atmospheric steam dump and turbine bypass valves are designed to remain shut until the main turbine trips.

For a turbine trip, the T_{avg} error from the RRS is used to control the atmospheric steam dump valve opening area. The larger of the secondary steam generator outlet pressure or T_{avg} error is selected to modulate the turbine bypass valve position following a turbine trip. If the T_{avg} error is greater than a set-point value (T_{avg} greater than 535°F usually at about 63% reactor power), both the atmospheric steam dump and turbine bypass valves receive a quick-open signal following turbine trip. Loss of condenser vacuum or MSIV closure will result in a quick-close signal to the turbine bypass valves. This signal will also prevent the turbine bypass valves from opening to prevent damage to the condenser.

Loss of dc bus 11 control power to the atmospheric steam dump and turbine bypass controls will close or hold closed the turbine bypass valves due to the quick-close action of the isolation solenoid valves. An automatic close demand will also be signalled for the atmospheric steam dump valves; however, manual control is also available for these valves. Loss of instrument power to the valves will serve to close both the atmospheric and turbine bypass valves.

The main steam system supplies steam to the auxiliary feedwater (AFW) pump turbines when the auxiliary feedwater system is actuated. The supply piping for the AFW pump turbines connects to each main steam header between the containment penetration and the main steam safety valves. Each supply line contains a steam supply isolation valve. These valves are air-operated globe valves which are held shut by air pressure from normally de-energized solenoid valves. The isolation valves fail open upon loss of instrument air pressure.

The main steam system supplies steam to the moisture separator reheaters of the reheat steam system. Main steam flows to the reheaters warming the HP turbine exhaust steam before it enters the LP turbines. Normally open isolation valves are provided on each line. These valves are motor operated and each is equipped with a handwheel to allow manual operation of the valve.

The main steam system has a dedicated drain system to provide removal of condensation from the main steam piping. This system assists in preventing turbine blade erosion and corrosion of the main steam piping. It also serves to improve plant operating efficiency by returning moisture from low points to the main condenser.

Additional details regarding operation of the main steam system can be found in ref. 6.

B.9 COMPONENT COOLING SYSTEM

The purpose of the component cooling system is to maintain certain plant components at their required operating temperatures by transferring heat to the salt water system. The system also acts as an intermediate barrier between the radioactive fluids in the components cooled and the ultimate heat sink--the salt water system.

The component cooling system consists of three circulating pumps, two heat exchangers, one chemical addition tank, and one head tank. Most of the components including piping, valves, and instrumentation are located in the auxiliary building. Cooling lines for containment components are located inside the containment. A simplified schematic of the component cooling system is shown in Figs. B16 and B17. For more information regarding the component cooling system, see ref. 7.

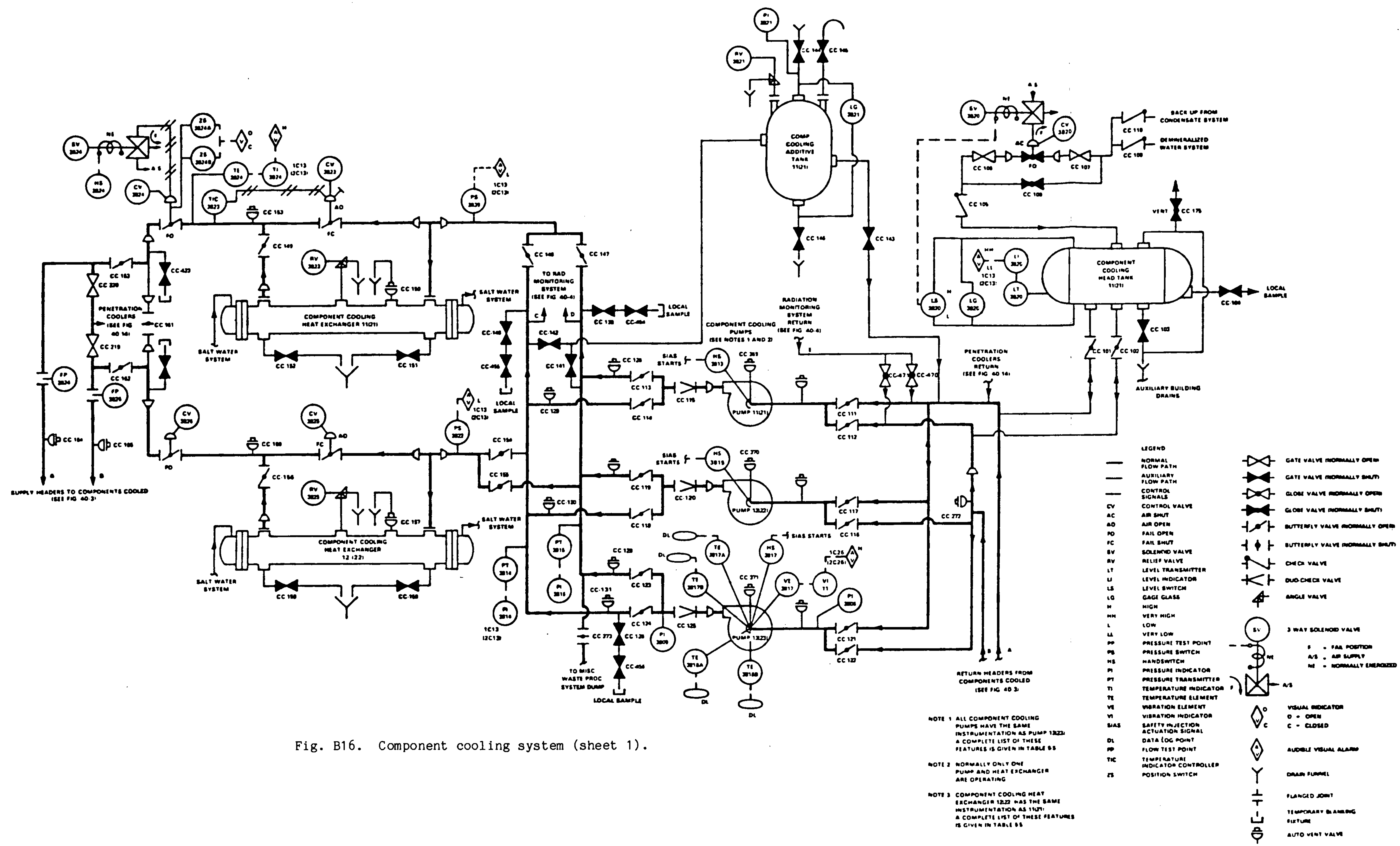


Fig. B16. Component cooling system (sheet 1).

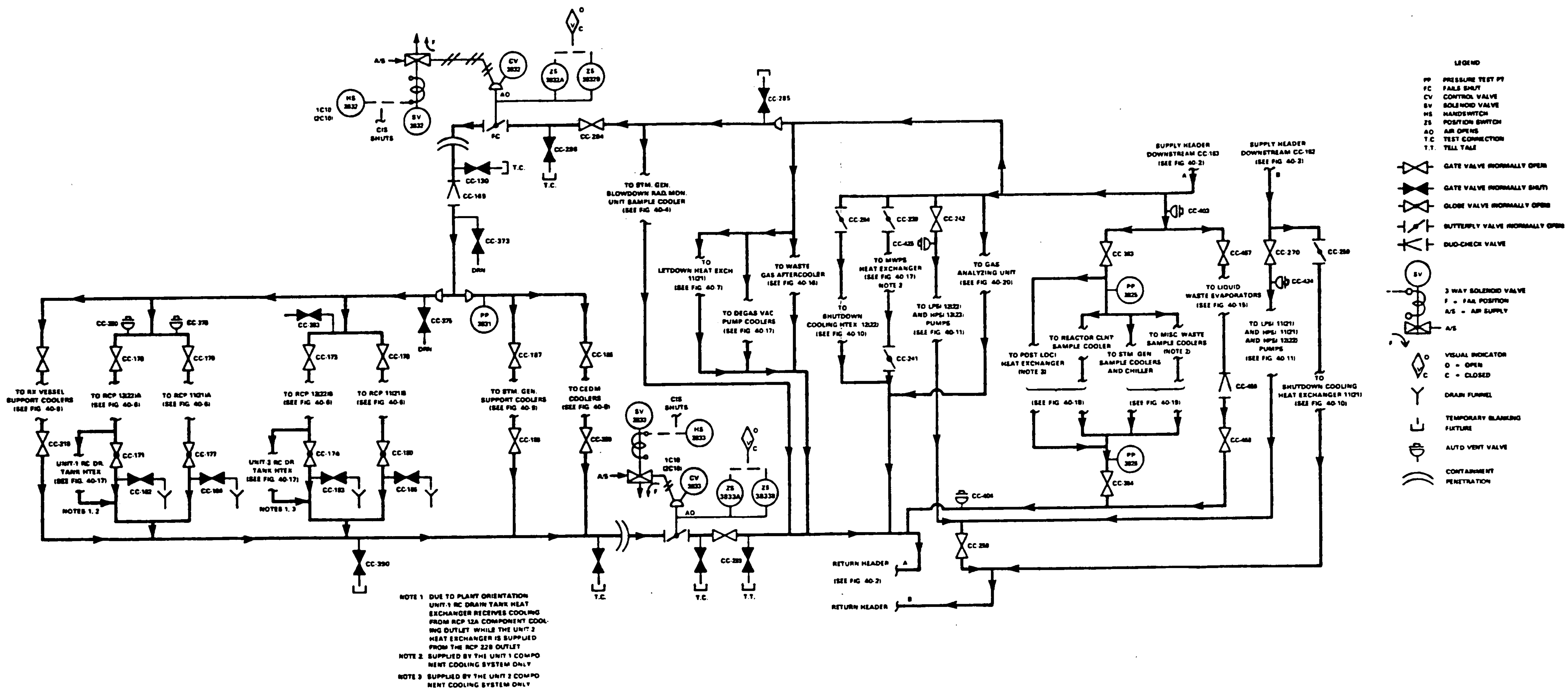


Fig. B17. Component cooling system (sheet 2).

The nonradioactive, chemically treated water circulated by the component cooling pumps supplies the following loads:

- shutdown cooling heat exchangers;
- letdown heat exchanger;
- mechanical seal cooler, lube oil cooler, and thermal barrier for each reactor coolant pump;
- control element drive mechanism coolers;
- cooling jacket and aftercooler for each waste gas compressor;
- mechanical seal cooler, stuffing box jackets, and bearing housings for each high-pressure safety injection (HPSI) pump;
- mechanical seal cooler, bearing house, and stuffing box jacket for each low-pressure safety injection (LPSI) pump;
- main steam, feedwater, reactor coolant letdown, reactor coolant sampling, and steam generator blowdown containment penetration coolers;
- reactor vessel support coolers;
- steam generator lateral support coolers;
- reactor coolant drain tank heat exchanger;
- reactor coolant sample cooler;
- post-LOCI (loss-of-coolant incident) sample vessel heat exchanger;
- steam generator blowdown sample coolers and chiller;
- miscellaneous waste sample coolers;
- gas analyzer sample coolers;
- concentrator condenser, distillate cooler, vacuum pump seal water cooler and vacuum pump discharge gas cooler for each waste evaporator;
- steam generator blowdown radiation monitor unit sample cooler;
- degasifier vacuum pump accumulator; and
- miscellaneous waste heat exchanger.

B.9.1 Flow Path

During normal operation, one component cooling pump takes suction from the two return headers and discharges to the normal and standby discharge headers. This water flows through the in-service component cooling heat exchanger, where heat is transferred to the salt water system. The temperature of heat exchanger outlet water is controlled to 95°F by automatic positioning of the heat exchanger bypass valve and operator throttling of the salt water outlet valve. Water leaving the heat exchanger flows in parallel paths to various plant components.

The head tank functions to maintain the net positive suction head to the component cooling pumps. It also serves to provide a surge volume for expansion and contraction of the system inventory.

The additive tank is used to change the chemical content of component cooling system water. Chemicals in the tank are dissolved in the water as the pump discharge is circulated to the tank.

B.9.2 Components

Three component cooling pumps are piped in parallel to the normal and standby supply headers. Each pump is designed to supply 5000 gpm at a discharge head of 100 ft. Each pump is driven by a 150-hp motor, which receives power from a 480-V bus. Component cooling pump 11 is powered by unit bus 11A, and pump 12 is powered by bus 14A. Component cooling pump 13 can be powered by either unit bus 11B or 14B. A key interlock prevents the potentially damaging arrangement of starting pump 13 from two different power sources.

During normal operation, only one pump is required for component cooling water circulation. Upon initiation of the SIAS, pumps 11 and 12 start automatically if not already operating. Failure of pump 11 or 12 to start within one second will result in the start of pump 13, provided its disconnects are selected to the appropriate bus.

Loss of power to the 480-V unit buses will cause the cooling pumps to trip. After the diesel starts and picks up the bus, the pumps can be restarted manually. If a SIAS has been initiated, the cooling pumps will automatically be sequenced back on.

The system contains pressure transmitters and alarms that detect and annunciate inadequate operation of the pumps. Operator action to restore component cooling flow is imperative for continued plant operation.

The component cooling system contains two 35 in. by 30 ft piped in parallel heat exchangers. Component cooling water flows through the shell while salt water flows through the tubes to provide cooling. Normal heat exchanger operation is such that the salt water heats 11 to 96°F, and the component cooling water cools 36 to 95°F.

During normal operation, one heat exchanger is sufficient to provide the necessary heat removal. The heat exchanger outlet temperature is maintained at 95°F for proper reactor coolant pump cooling by control of the temperature control bypass valve.

The other component cooling heat exchanger is normally placed in standby to increase system availability and reliability. In this mode, the heat exchanger is lined up for normal operation with the exception of the salt water outlet and heat exchanger outlet valves, which are closed. In order to maintain proper component cooling outlet temperature, these valves are opened as necessary. Plant cooldown and post-LOCI cooldown are normally accomplished using both exchangers. Both heat exchangers may also be necessary during hot weather when the salt water temperature is warmer.

A component cooling head tank is used to provide static head to the component cooling system through two normally open butterfly valves.

The head from this tank provides more than the minimum net positive suction head for the component cooling pumps. This 2550-gal tank also serves as a surge volume for contraction and expansion due to temperature changes in the closed system. Makeup is provided to the system via the head tank by the demineralized water system and the condensate system. The head tank is provided with transmitters to annunciate high and low level conditions.

A 75-gal additive tank is provided for addition of a corrosion inhibitor to the component cooling system. On a weekly basis the component cooling water is sampled for corrosion inhibitance. Hydrazine must be added occasionally to increase the corrosion inhibitance level. After chemical addition to the additive tank is completed, the operator establishes a flow path from the discharge of the pumps, through the tank, and back to the pumps' suction. After adequate mixing into the system, the flow is secured and the tank is placed in a wet layup condition.

B.9.3 Component Cooling System Interfaces

The component cooling system interfaces with numerous systems throughout the plant. Most of these interfaces are the loads which the component cooling system supplies cooling water. The major interfaces are discussed in this section.

The component cooling system interfaces with the radiation monitoring system, but does not provide cooling water. Component cooling water is circulated through the radiation monitoring system radiation detectors to determine if there is any activity in the water. An indication of high radioactivity in the water is indicative of a reactor coolant leak. Upon receipt of a high activity alarm, the operator determines the validity of the alarm by

- reading the activity level indication on the radiation monitor,
- sampling the component cooling system, and
- monitoring the head tank level.

If high activity exists, it is imperative that the operator "feed and bleed" the system to reduce the activity. To feed and bleed the system, pure water is added to the head tank from the demineralized water system, and activated water is diverted to the miscellaneous waste processing system.

Component cooling is provided to each of the four reactor coolant pumps. The flow path to each pump is subdivided into two streams; one for pump seal cooling and the other for motor bearing lube oil cooling.

Pump seal cooling is divided into two side streams:

- thermal barrier cooling, which receives 17 gpm, and
- seal water cooling, which receives 28 gpm.

Component cooling to the reactor coolant pumps must be controlled such that the bleedoff temperature from the thermal barrier does not fall below 125°F and the seal cavity temperature does not exceed 250°F. Component cooling water must be maintained to RCPs whenever the coolant temperature is greater than 175°F.

The cooling water to the motor bearing lube oil coolers is also divided into two streams; 150 gpm supplies the upper bearing lube oil cooler and 5 gpm supplies the lower bearing lube oil cooler. Proper cooling of the lube oil is necessary to prevent damage of these bearings and subsequent motor damage. The heat load generated to the motor bearings is so great that cooling water must be maintained for thirty minutes after the RCP is tripped.

Loss of component cooling has a significant impact on continued plant operations due to cooling loss to the RCPs. Component cooling must be restored to operating RCPs within 10 min to prevent damage. The operator is instructed to immediately stop the affected RCP if one of the following conditions exists:

- flow is not restored within 10 min,
- seal cavity temperature reaches 200°F, or
- thrust bearing temperature reaches 195°F.

The letdown heat exchanger uses component cooling water to cool the letdown from the outlet of the chemical and volume control system regenerative heat exchanger. The purpose of this heat exchanger is to provide sufficient cooling to the RCS letdown for ion exchanger operation. Temperatures exceeding 145°F can damage the ion exchanger resin.

Component cooling water flow must be adjusted to provide a constant letdown temperature to the ion exchangers. A reduction in ion exchanger inlet temperature increases the resin's ability for boron capture because the ion exchanger affinity for boron is temperature dependent. Greater boron capture results in increased reactor power, while decreasing boron capture (higher inlet temperature) results in a power decrease. Due to this temperature dependence, the operator must be especially alert to changing heat loads on the component cooling system. The power increases described above are not significant in magnitude but may result in an excursion above 100% power since normal operations are usually held at full power. The operator may anticipate major temperature changes and bypass the ion exchangers accordingly.

Cooling water is also supplied to two control element drive mechanism (CEDM) water-to-air coolers. This cooling permits long-term operation and minimizes CEDM maintenance. Cooling water flows through the CEDM coils removing heat from the CEDM shroud exhaust.

When the CEDMs are energized, the component cooling system should be in operation to assist the CEDM ventilation system in maintaining the power coils below 350°F. Each mechanism is provided a constant 800-cfm air flow with an inlet temperature of 120°F. Loss of component cooling does not have a critical impact unless air flow is also lost. Loss of water cooling to CEDM shortens coil life. As the temperature increases, the coil resistance for each CEDM increases, causing a current decrease. Eventually, the control rods drop due to insufficient current.

Component cooling water is provided to three reactor vessel support coolers and four steam generator lateral support coolers. This cooling water flow protects the support bearing surfaces and structural concrete from exceeding allowable temperatures in order to achieve a 40-y life expectancy. Short-term loss of component cooling to the support coolers is not expected to result in significant failures.

Component cooling water is supplied to the two shutdown cooling heat exchangers during plant cooldown, cold shutdown, and post-LOCI cooldown. During normal operation, the shutdown heat exchangers are lined up to cool the containment spray in the event of a CSAS. During shutdown cooling, two component cooling pumps and two component cooling heat exchangers are placed in service. For long-term cooling following a LOCI, one pump and two heat exchangers are necessary to cool both shutdown cooling heat exchangers.

In the event of a SIAS, the shutdown heat exchanger outlet control valves open automatically by a control signal to the solenoid valve. The shutdown cooling heat exchangers are then able to support containment spray cooling and long-term cooling following a LOCI.

The high-pressure safety injection (HPSI) pumps are supplied cooling water via the component cooling system. The HPSI pumps inject borated water into the RCS during a loss-of-reactor-coolant accident. Due to their safety function, these pumps have been designed to operate 2 h without cooling. These centrifugal pumps require seal, bearing, and stuffing box cooling for proper sustained operation.

The low-pressure safety injection (LPSI) pumps also receive cooling water via the component cooling water system. These pumps are also designed to operate 2 h without cooling water. During normal operation, flow through the pumps is not required, but is maintained in preparation for their sudden start. The LPSI pumps serve two purposes:

- inject large quantities of borated water into RCS during a LOCI.
- provide flow through the reactor core and shutdown cooling heat exchangers during shutdown cooling.

Component cooling water also flows through the containment penetration coolers for the following penetrations:

- main steam,
- feedwater,
- steam generator blowdown,
- reactor coolant letdown, and
- reactor coolant sampling.

The purpose of these coolers is to reduce thermal stress on the containment. Complete loss of cooling will not result in any significant failure, but the concrete in the areas of the penetrations will be weakened.

The reactor coolant waste evaporators and the miscellaneous waste evaporator require cooling water and represent a major load on the component cooling system when placed in operation. The primary cooling load for the waste evaporators is the concentrator condenser, which requires 1100 gpm of cooling water. During a LOCI, the CIS closes the waste evaporator supply isolation control valves, eliminating these major nonsafety loads. In the event of loss of component cooling, the operator should secure the evaporator to prevent damage and possible personnel injury.

Component cooling water is supplied to the waste gas compressor when it cycles on. The purpose of these compressors is to compress gases collected in the surge tank for discharge to the gas decay tanks.

Component cooling water is continuously supplied to the reactor coolant drain tank heat exchanger. Heat exchanger cooling is necessary to protect the reactor coolant drain tank from overheating and overpressurization.

B.10 SERVICE WATER SYSTEM

The service water (SRW) system is designed to remove heat from turbine plant components, containment cooling units, the spent fuel pool, and emergency diesel generator heat exchangers. Heat is transferred from the SRW system to the salt water system via the SRW system heat exchangers. This section provides a description of the SRW system (for more information, see ref. 8). Figure B18 provides a functional block diagram of the SRW system.

The SRW system functions as one system in the turbine building and as two subsystems in the auxiliary building. The two subsystems are required to function independently to the degree necessary to assure safe shutdown of the plant in the event of a component failure. Each

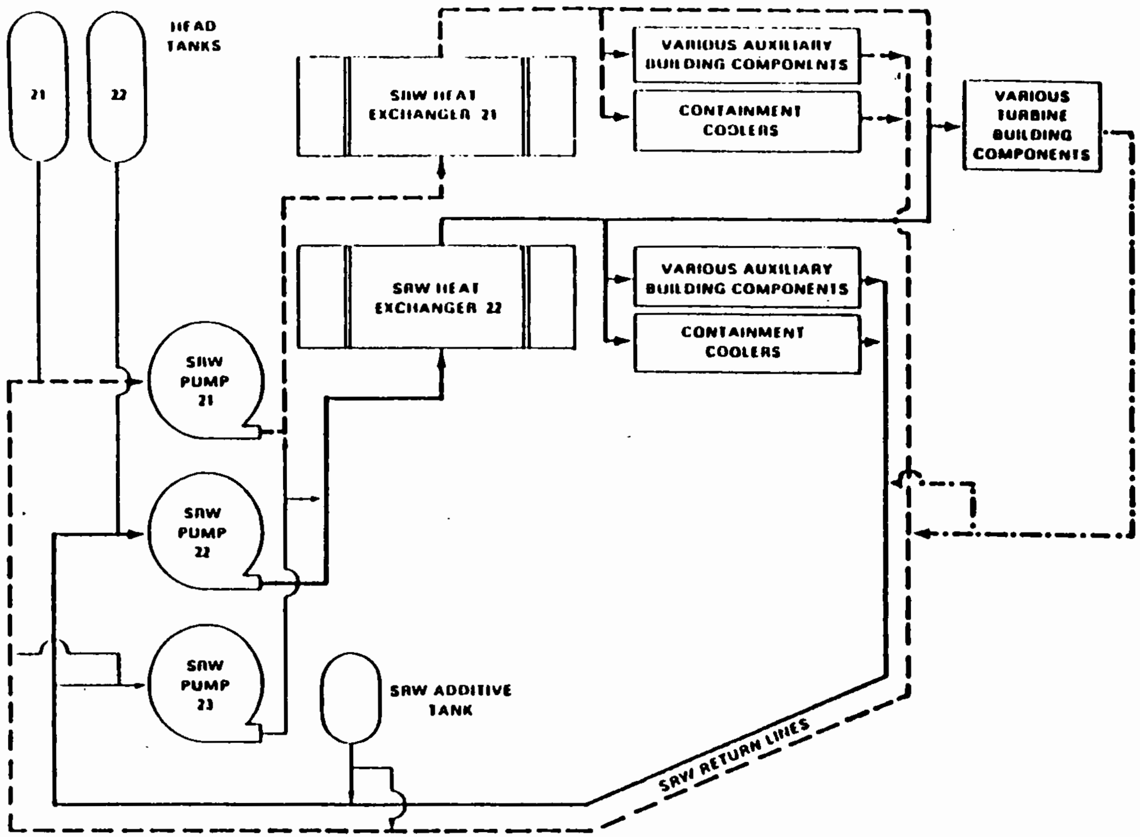


Fig. B18. Service water system block diagram.

subsystem includes a head tank, an electric-driven pump, and a heat exchanger. A third SRW pump is provided as backup and may be cross connected to supply either subsystem.

The SRW system provides heat removal for the following components in the auxiliary building:

- two spent fuel pool cooling heat exchangers
- four containment air coolers
- three emergency diesel generators
- two SG blowdown recovery heat exchangers.

Turbine building components receive cooling water through four air-operated isolation valves. These valves shut on a SIAS to reduce the heat load and isolate nonsafety related equipment. The SRW system supplies cooling water to the following components in the turbine building:

- three circulating water system priming pumps
- four condenser vacuum pump seal water coolers
- three condensate booster pump seal water and lube oil coolers
- three air compressors and three after coolers
- electrohydraulic power plant oil coolers
- auxiliary feed pump room air conditioner condenser
- main feed pump lube oil coolers
- two turbine lube oil coolers
- four hydrogen coolers
- generator exciter air coolers
- two generator isolated phase bus duct coolers
- sampling system mechanical chillers
- nitrogen compressor.

During normal plant operation, two of the three SRW system pumps are operating with the third pump in standby. The third pump is normally aligned to subsystem 12 and electrically powered from 4-kV bus 11. Both SRW heat exchangers are used during normal plant operation.

During a LOCI, a SIAS will automatically start the primary SRW pumps if they are not already operating. If either fails to start, the standby pump will be started. A SIAS will also isolate service water flow to turbine building components, reducing nonessential system heat load. A CSAS will cause valves in the containment coolers to open, increasing SRW flow through the coolers.

B.10.1 Components

Service Water Head Tanks

Two 2300-gal head tanks provide positive suction head for the SRW system. The head tank level is automatically maintained by a level control valve.

A level switch for each tank signals a solenoid valve to close, which permits the level control valve to open. Makeup water to the head tanks is supplied from the demineralized water system or the condensate system.

Service Water Pumps and Motors

Each of the three SRW pumps is driven by a 400-hp electric motor that rotates at 1185 rpm. Each pump is able to supply 7050 gpm at a 180-ft head. The pump seals are lubricated by controlled water leakage past the seals. Instrumentation is provided on each pump to detect bearing temperatures and excessive vibration.

The normally operating pumps (11 and 12) take suction from the subsystem return header via a butterfly isolation valve. The pumps discharge service water through a check valve and isolation valve to the subsystem discharge header. The discharge headers contain temperature and pressure sensors that energize an alarm on low (<85 psig) pressure. The discharge headers supply water to service water heat exchangers and are connected to the chemical additive tank and the miscellaneous waste processing system.

SRW pump 11 receives power from 4-kV bus 11, while pump 12 receives power from 4-kV bus 14. SRW pump 13 may receive power from bus 11 or 14, depending upon how its disconnect links are aligned. Kirk-key type interlocks prevent pump 13 from being energized from two buses simultaneously. SRW pumps 11 and 12 contain start and stop logic circuitry. Start cycle limitations are imposed on the pumps because of excessive heat generation in the windings caused by the starting circuit.

Service Water Heat Exchangers

Two service water heat exchangers transfer heat from the service water on the shell side to salt water on the tube side. Design temperature and pressure of the tube side of the heat exchanger are 200°F and 50 psi, while shell side parameters are 200°F and 175 psi. Actual operating conditions are substantially lower.

SRW temperature entering the shell side of the heat exchanger is 110°F and exit temperature is 95°F. Salt water temperature entering the tubes is 85°F and exit temperature is 95°F. Normal inlet temperature on the tube side will vary with seasonal temperatures. The design heat load on each heat exchanger is 105 x 10^6 Btu/h, and 120 x 10^6 Btu/h during a LOCI. The salt water outlet of each heat exchanger has a temperature indicator which annunciates in the Control Room if the temperature reaches 95°F.

The heat exchangers were designed based on maximum salt water flow, and the salt water flow should be at maximum prior to admission of service water to the shell. During shutdown operation, salt water flow should be continued until the SRW pumps have been stopped. Care should be exercised during startup of a heat exchanger to assure that it is properly vented; an air-free system must be maintained to ensure proper system operation. Periodic monitoring of heat exchanger temperature and pressure is necessary to assure proper operation.

Chemical Additive Tank

The SRW system is designed to permit addition of chemicals and discharge of service water should it become contaminated. In order to minimize corrosion in the system, hydrazine may be added to the system. A 75-gal chemical addition tank is included in the system to provide dissolution of chemicals into the system. Differential pressure across the SRW pump provides the driving head for chemical injection.

Should the service water system become contaminated with radioactivity, provisions are incorporated in the design to permit discharge of contaminated water to the miscellaneous waste processing system. Contamination is reduced by dilution of the system with water from the demineralized water system. Valve SRW-305 may be opened to permit discharge of service water to the miscellaneous waste processing system.

B.10.2 Auxiliary Building Loads

The SRW system is divided into two subsystems in the auxiliary building in order to meet the single-failure design criteria. Auxiliary building heat loads are safety-related with the exception of the blowdown recovery heat exchanger.

Spent Fuel Pool Cooling Heat Exchangers

Two spent fuel pool cooling heat exchangers maintain the pool temperature below the design limit. These heat exchangers are horizontal, counterflow type with a SRW inlet temperature of 95°F and an outlet temperature of 106.5°F. Heat exchanger 11 is supplied service water from Unit 1 subsystem 12 header, while exchanger 12 is supplied by a Unit 2 subsystem header.

Service water is supplied to the shell side of the heat exchanger and pool water is supplied to the tubes. Upon receipt of a CSAS, the inlet and outlet control valves automatically close in order to provide maximum flow to the containment coolers. These valves are designed to fail shut upon loss of control power or loss of pneumatic supply.

The return line from the heat exchanger is monitored for radioactivity, and readings in excess of 1000 counts/min are alarmed in the Control Room. An alarm would be indicative of a heat exchanger tube failure with failed fuel in the pool.

Containment Coolers

Four containment coolers are provided in each unit to remove heat from the containment during normal operation and also in the event of a LOCI. Containment coolers 11 and 12 are normally supplied by SRW subsystem 11, with coolers 13 and 14 supplied by subsystem 12. However, manual valves are in place to permit the supply of any cooler by either header. The supply line to each cooler has an air-operated, normally open stop valve. These valves are designed to fail in the open position.

The return line from each cooler contains two air-operated stop valves piped in parallel. One valve located on a 4-in. line is used for normal operation cooling requirements. The parallel line is 8 in. diam. and its valve is automatically opened upon receipt of a CSAS. A third parallel, manually operated valve is also provided to permit flow should the 8-in. valve fail following a CSAS.

During normal operation, less than four coolers are operating to remove containment heat. The fourth cooler usually serves as a spare with its inlet valve open and outlet valve shut. Depending on weather conditions, the fourth cooler may be valved into operation. Each containment cooler has a normal flow of 550 gpm with a heat removal capability of 2.2×10^6 Btu/h. During a LOCI the water flow is increased to 2000 gpm by the opening of the parallel 8-in. valve, which boosts the heat removal capability to 95×10^6 Btu/h.

Emergency Diesel Generator

Three emergency diesel generators are supplied service water for cooling of the heat exchangers for lube oil, diesel jacket water, and diesel air subsystems. Service water flows through the tubes of all three exchangers.

Diesel generator 11 receives service water from Unit 1 subsystem 11, while Unit 2 SRW subsystem 22 supplies diesel 21. Diesel 12 may receive service water from either Unit 1 subsystem 12 or Unit 2 subsystem 21. Pressure-sensing valves, located in the supply and return line of each subsystem, sense subsystem pressure and the position of the alternate supply and return sensing valves. If any deviation in normal operation of the primary subsystem is detected, the pressure-sensing valves shut and the alternate set of pressure-sensing valves open automatically. These valves fail open upon loss of instrument air.

Additional redundancy is provided by cross-connects in the service water system design. Diesel generator 12 can also receive service water from Unit 1 subsystem 11 by opening two manual valves. Unit 2 subsystem 22 may also supply diesel 12 by opening two other manual valves. The same sets of cross-connects may be used to supply diesel 21 from Unit 1 subsystem 12, and diesel 11 from Unit 2 subsystem 21.

Service water is supplied to each diesel generator through an air-operated cooling water supply valve. These valves automatically open upon receipt of a signal from the diesel jacket coolant pump speed switch. These valves, once opened, are modulated by a differential pressure controller that maintains 5 to 7 psid across the three diesel generator heat exchangers.

Blowdown Recovery Heat Exchanger

The SRW system supplies cooling to two blowdown recovery heat exchangers, one located in each plant. There are two blowdown recovery heat exchangers in series; one is cooled by condensate and the other by service water.

The service water flows through the tube side with a design pressure and temperature of 350 psig and 200°F. Service water enters the heat exchanger through manually operated valves. Service water temperature and pressure are indicated locally on the discharge side of the heat exchanger. Overpressure protection is provided by relief valves on both the shell and tube sides of the heat exchanger.

B.10.3 Turbine Building Loads

The turbine building components receive service water through air-operated valves SRW 1600-CV, 1637, 1638, and 1639. These valves are automatically shut on a SIAS to permit additional flow to the containment coolers.

Circulating Water System Primary Pumps

Service water is supplied to the priming pump seal water coolers through manually operated inlet and outlet valves. Two of the three priming pumps are normally in automatic operation with service water flowing to the seal water coolers. Standby pump cooler inlet and outlet valves are closed, and outlet valves on the operating coolers are throttled to maintain optimum outlet temperature.

Condenser Vacuum Pump Seal Water Coolers

Service water is supplied to four condenser vacuum pump seal water coolers through a pressure regulating valve, CV-1627. This valve is maintained at 80 psig by a pressure-indicating controller. During normal operation service water is supplied to three pump coolers, although only two of the pumps are operating. The standby pump is ready for automatic starting if needed. The fourth pump is isolated with its SRW inlet and outlet valves closed. The outlet valves for the pump seal water coolers are throttled to maintain the optimum temperature for pump operation.

Condensate Booster Pump Lube Oil and Seal Water Coolers

Service water is supplied to condensate booster pumps for both lube oil and seal water cooling. Service water is supplied to the lube oil coolers via manually operated inlet and outlet valves. Temperature control valves on the service water outlet of the lube oil coolers maintain the temperature between 110 and 120°F. Two seal water coolers are provided for each condensate booster pump, one for each end seal.

Compressed Air System

Each Calvert Cliffs unit has a compressed air system that includes two instrument air compressors, one plant air compressor, and three aftercoolers. Service water pressure to these components is regulated at 55 psig by pressure control valve SRW-1628-PCV. Flow to each component is directed through a solenoid-operated supply valve. These valves open automatically on a signal from the compressor motor controller. Service water flow through the compressor cooling jacket is automatically adjusted by a temperature control valve to maintain the outlet water temperature at 110°F. The aftercooler valve is manually throttled to maintain the outlet temperature within 15°F of the inlet temperature.

Eight pressure relief valves provide overpressure protection for the compressors and aftercoolers. Temperature indication is also provided for the three components including the inlet of each compressor and the outlet of each compressor and aftercooler. Auto vent valves are installed to prevent an air-to-water leak, which would air bind the SRW system.

Electrohydraulic Control System Oil Coolers

The SRW system supplies cooling water to two electrohydraulic oil coolers. Each cooler has temperature indication as well as overpressurization protection. Service water flow through the coolers is modulated by control valve SRW-1628-CV on the supply header. This control valve is positioned by a temperature-indicating controller to maintain the oil temperature between 110 and 115°F. During normal plant operations, only one cooler is necessary to cool the heat load from the electrohydraulic control system.

Auxiliary Feed Pump Room Air Conditioner Condenser

Service water is supplied to the auxiliary feedwater pump room air conditioner condenser to remove heat. Flow to the condenser is regulated by a pressure control valve, and two manually operated valves are provided for isolation of the condenser.

Main Feed Pump Lube Oil Coolers

Service water is supplied to the main feed pump lube oil coolers, which are located next to the feed pump lube oil reservoir. A temperature-indicating controller maintains the lube oil temperature between 120 and 130°F. Each cooler has temperature indication and pressure relief protection.

Turbine Lube Oil Coolers

Each unit contains one turbine lube oil cooler, which is supplied flow from the SRW system at 2000 gpm. A control valve automatically adjusts the flow of service water to maintain the lube oil reservoir temperature between 120 and 130°F. A temperature-indicating controller positions the service water control valve.

Generator Hydrogen Coolers

Service water is supplied to four generator hydrogen coolers located on top of and inside the unit generator casings. The service water manually operated inlet and outlet valves are normally open. The hydrogen temperature is regulated by a temperature-indicating controller, which modulates the control valve (CV-1608) on the service water outlet of the cooler. The temperature-indicating controller maintains the hydrogen cooler outlet temperature between 80 and 114°F.

Generator Stator Liquid Cooler

Service water is also used to remove heat from the generator stator. Two stator liquid coolers are provided on Unit 1, and during normal operation service water is supplied to both. Constant service water flow is maintained and temperature control is determined to be unnecessary. Pressure and temperature indication is provided on the cooler outlet side; overpressure protection is provided by a relief valve set at 150 psi.

Generator Exciter Air Coolers

Service water is used for heat removal from the generator exciter air cooler located inside the generator housing. The temperature is regulated by modulating a control valve on the outlet side of the cooler. A temperature-indicating controller maintains the temperature between 120 and 130°F.

Generator Isolated Phase Bus Duct Coolers

Two generator isolated phase bus duct coolers are cooled by service water. The coolers are located inside a housing on each end of the turbine building. Circulating fans move air over the coolers to transfer heat from the generator buses. The inlet and outlet isolation valves are normally in the open position. Two control valves open to admit service water flow through the coolers when the circulating fans are energized. The valves are not throttled because temperature control is unnecessary.

Turbine Plant Sampling System Coolers

Service water is supplied to the mechanical chillers used to cool the isothermal bath heat exchangers. The chiller inlet valve is normally open, and the manually operated outlet valve is used to throttle the service water flow. No temperature limits have been established for the service water flow.

Nitrogen Compressor Cooler

Service water is used for heat removal from the nitrogen compressor interstage and aftercooler. Service water inlet pressure is maintained at 55 psig by a pressure control valve. No specific temperature limits have been established, but the outlet valve is throttled to maintain the temperature of the compressor warm to the touch.

B.11 SALT WATER COOLING SYSTEM

The purpose of the salt water system is to transfer heat from various turbine and reactor plant components to Chesapeake Bay. It also supplies cooling water to the circulating water pump seals, the condenser tube bulleting system, and the water jet exhauster. This section is a brief description of the salt water system abstracted from ref. 9. Figure B19 is a schematic diagram of the salt water system.

B.11.1 System Components

The salt water system consists of three pumps and the necessary piping for distribution of the bay water to the proper components and its return to the discharge conduit. There are two supply headers, 11 and 12. Supply header 11 may be used as an emergency discharge header in the event of a rupture downstream of the emergency core cooling system pump room air coolers, component cooling, or service water heat exchangers. Header 11 can be supplied by salt water pumps 11 or 13; header 12 can be supplied by salt water pumps 12 or 13.

Power to the salt water pump motors comes from the plant 4160-V bus. Salt water pump motor 11 receives power from 4-kV bus 11 and salt water pump motor 12 receives power from 4-kV bus 14. Pump 13 can receive its power from either bus 11 or 14 using key-operated disconnect links located in the switchgear rooms.

Pumps 11 and 12 will automatically start on a SIAS or SDS signal if their control switches are in the "auto" position. Pump 13 starts only

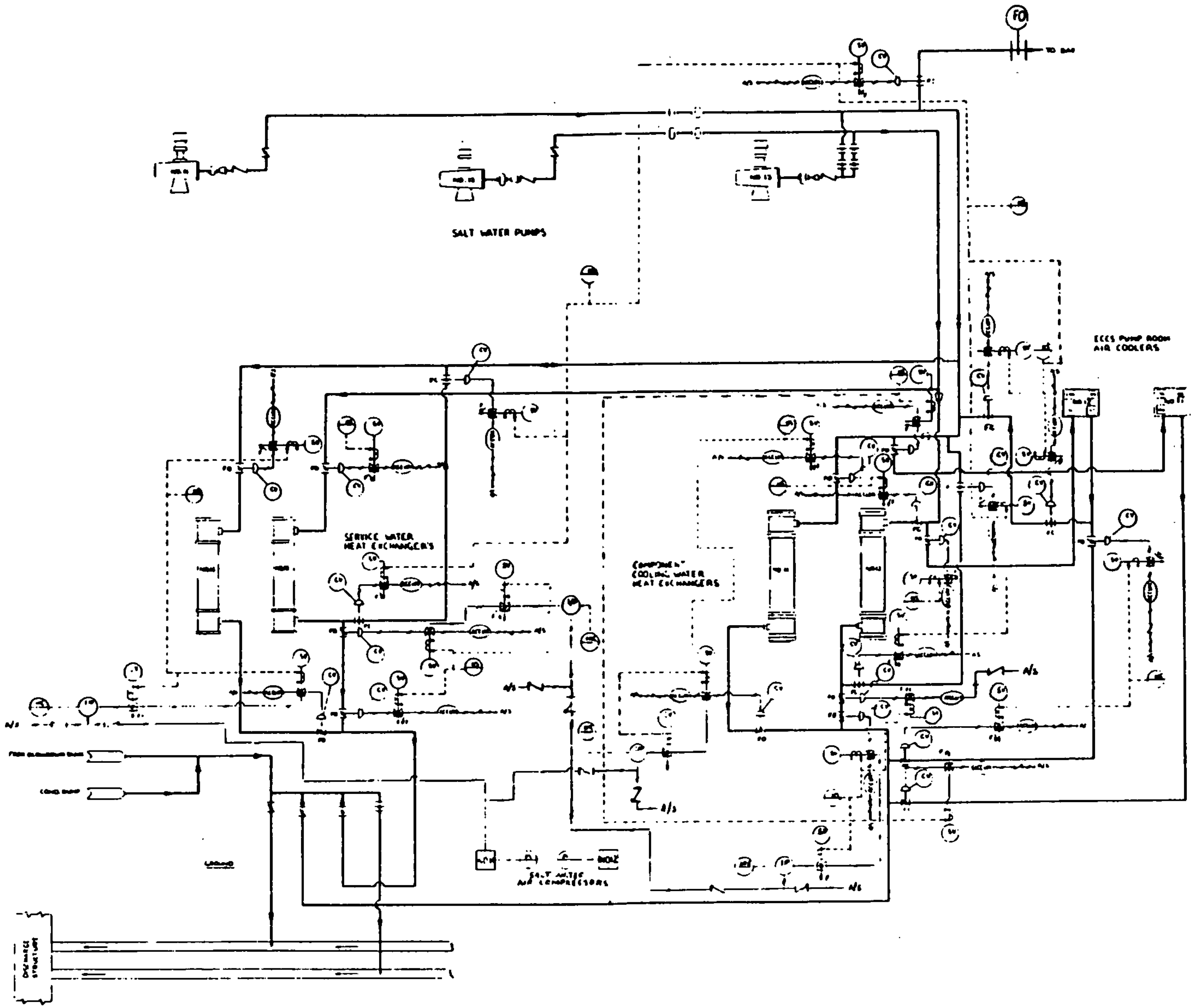


Fig. B19. Salt water cooling system.

if the other pump motor, which is connected to the same bus, fails to start within 1 s of receiving the start signal. The motor on pump 13 is interlocked so that it can not be energized from two different buses at the same time.

Each unit at Calvert Cliffs has three pumps, each able to supply 15,500 gpm at 68 ft head. Each pump is a single-stage centrifugal unit driven by a 450-hp electric motor. Salt water demand during power operation is 31,000 gpm, requiring operation of both pumps. Following a LOCI, one salt water pump is sufficient to supply the cooling water requirements of a unit.

B.11.2 System Loads

Circulating Water Pump Seals

The circulating water pump seals are supplied filtered salt water from either pump header 11 or 12. This seal water is maintained at 12 to 15 psig with a flow rate of 3 to 6 gpm by a pressure control valve. A low-pressure alarm annunciates on a control room panel when the pressure drops to 11 psig.

Condenser Tube Bulleting System

The tube bulleting system is supplied by salt water supply header 12 via the salt water booster pump. The salt water booster pump is used to raise the header pressure from 40 to 200 psig to facilitate tube bulleting. This is the only place at which the two Calvert Cliffs units can be cross-connected. The tube bulleting system normally is shut down and its salt water supply valve from No. 12 salt water supply header is shut.

Circulating Water Pump Room Air Coolers

Six air coolers are used to remove the heat produced by operation of the circulating water pump motors. These coolers are supplied by salt water supply header 12 only. These coolers are isolated by closing two motor operated valves upon receipt of a SIAS. Flow at the outlet of the coolers is mechanically adjusted and set at startup.

Water Jet Exhauster

The jet exhauster is supplied salt water to provide startup of the screen wash system. Once a screen wash pump is running and the screen wash header is pressurized, it alone can facilitate priming of the other screen wash pumps. Upon a SIAS, the water jet exhauster salt water supply will be shut off.

Component Cooling Heat Exchangers

No. 11 component cooling heat exchanger is supplied salt water from salt water supply header 11, while heat exchanger 12 is supplied from header 12. The salt water supply inlet and outlet control valves are opened and shut by the same hand switch. A SIAS closes both valves so that maximum cooling can be supplied to the containment coolers. Both control valves are reopened upon a RAS to provide cooling of the containment spray.

ECCS Pump Room Air Cooler

Pump room air coolers 11 and 12 are supplied by salt water headers 11 and 12 respectively. Two remotely operated control valves are associated with ECCS pump room air cooler No. 11. Both valves can be opened by the same hand switch, or both valves are opened when the cooler fans receive a start signal from a local temperature switch.

Service Water Heat Exchangers

Service water heat exchangers 11 and 12 are supplied by salt water headers 11 and 12 respectively. Each heat exchanger has two remotely operated control valves, one each for the inlet and the outlet. A hand indicating controller enables throttling of the outlet control valve for control of SRW system temperature.

B.12 CALVERT CLIFFS AC ELECTRICAL DISTRIBUTION SYSTEM

B.12.1 500-kV System

The following description applies to Calvert Cliffs-1, but because Units 1 and 2 are electrically interconnected, much of the description includes Unit 2 equipment. The system description begins with the 500-kV switchyard and includes each voltage level down to the 120-V ac instrument buses.

The 500-kV switchyard is designed to be the interconnection point between the plant electrical distribution system and the bulk power transmission system. (Refer to Fig. B20 for the following description.) Electric power is supplied from the power grid system to the switchyard by two physically independent transmission lines (5051 and 5052). Two physically independent circuits supply electric power from the switchyard to the on-site electrical distribution system through the two 500-kV/13.8-kV plant service transformers (P-13000-1 and P-13000-2). The main generators feed electrical power generated at 25 kV and 22 kV for Units 1 and 2, respectively, through the unit transformers (U-25000 and U-22000) to the 500-kV switchyard.

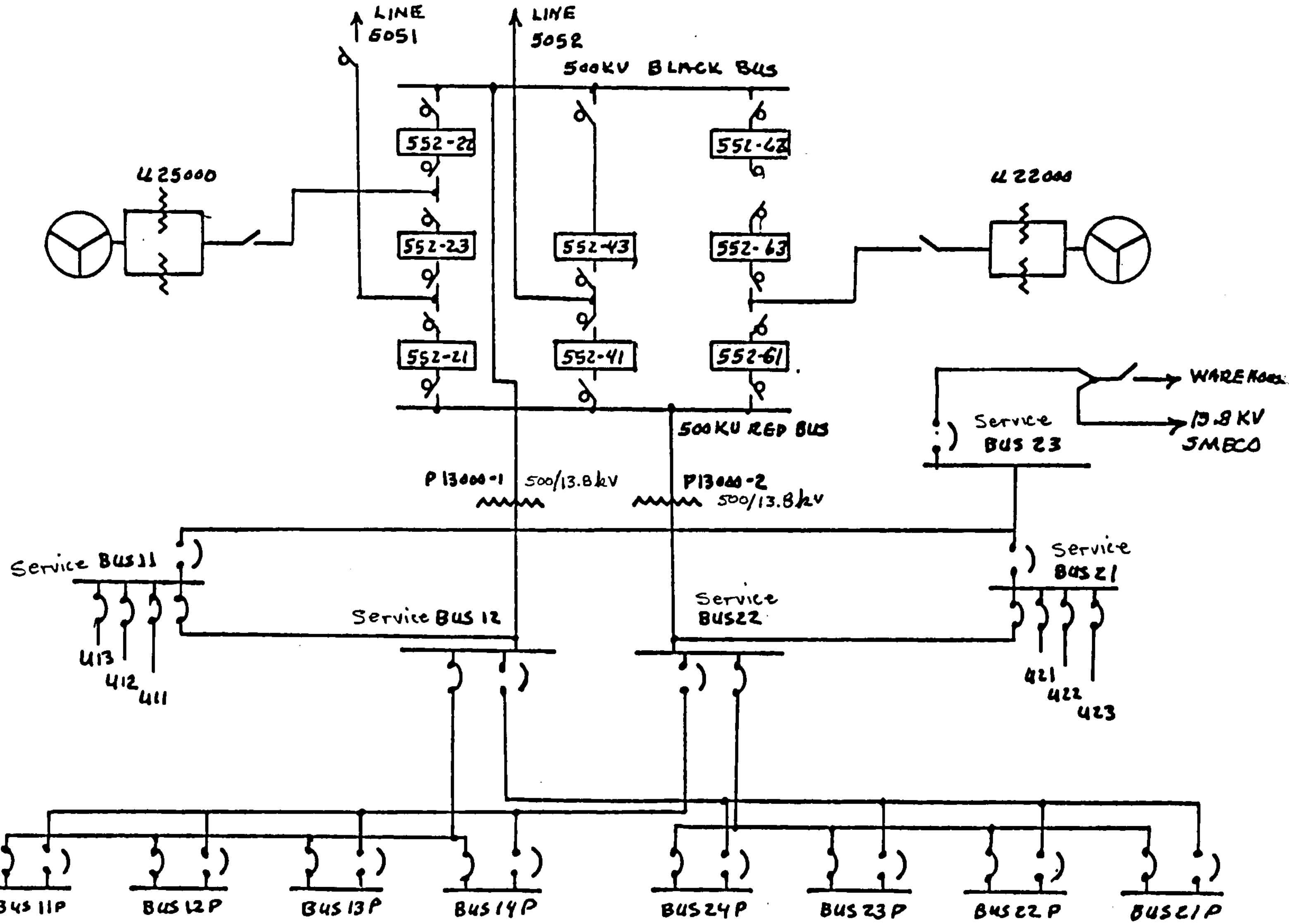


Fig. B20. 500 kV and 13.8 kV distribution.

The 500-kV switchyard normally operates with all breakers closed. Opening and closing the breakers can be accomplished locally in the switchyard control house or remotely from the plant main control room. The circuit breakers have dual trip coils on separate isolated dc control circuits and breaker failure relays to trip adjacent breakers. The 125-V dc control power is supplied from two 59-cell batteries located in the switchyard. Each can supply the switchyard dc power requirements for 8 h without recharging. Two battery chargers (powered from 4-kV ESF buses 11 and 21) keep the batteries fully charged and supply the 125-V dc power requirements under normal conditions.

B.12.2 13.8-kV System

The plant (Units 1 and 2) 13.8-kV distribution system (Fig. B20) consists of two 500-kV/13.8-kV plant service transformers (P-13000-1 and P-13000-2); five service buses (11, 12, 21, 22, and 23); eight reactor coolant pump buses (11P, 12P, 13P, 14P, 21P, 22P, 23P, and 24P); and one 13.8-kV line from Southern Maryland Electric Cooperative (SMECO). Service buses 12 and 22 supply power to the reactor coolant pump buses, and service buses 11 and 21 supply power to the 4160-V distribution system through the six 13.8-kV/4.16-kV service transformers (U-4000-11, -12, -13, -21, -22, and -23). Service bus 23 receives power from the SMECO 13.8-kV line and can be used to supply either bus 11 or 21 to supply the power necessary to maintain both units in a safe shutdown condition in the event normal off-site power fails.

The 13.8-kV unit switchgear for the service buses is metal clad with removable air circuit breakers designed for outdoor installation. Relay protection, ground connections, and structural safeguards are provided to assure adequate personnel protection and to prevent or mitigate equipment damage during system fault conditions. Dc control power is required for remote control and for operation of the protective relays of the 13.8-kV circuit breakers.

Operation of all 13.8-kV equipment is effected and monitored in the control room. During normal operation both plant service transformers are energized and share the total plant load. The capacities of the two plant service transformers and associated switchgear and cable are such that either one of the transformers can supply the total auxiliary load of both units but not the normal operating load of both units. All reactor coolant pump motors (RCPs) for Unit 1 are fed from service transformer P-13000-1 and the RCPs for Unit 2 from service transformer P-13000-2.

B.12.3 4160-V System

The 4160-V distribution system (Fig. B21) is designed to supply power during normal and accident conditions. The system will supply power to the 4160-V auxiliary loads from the 13.8-kV system through the six unit service transformers to twelve 4160-V buses (11, 12, 13, 14, 15, 16, 21,

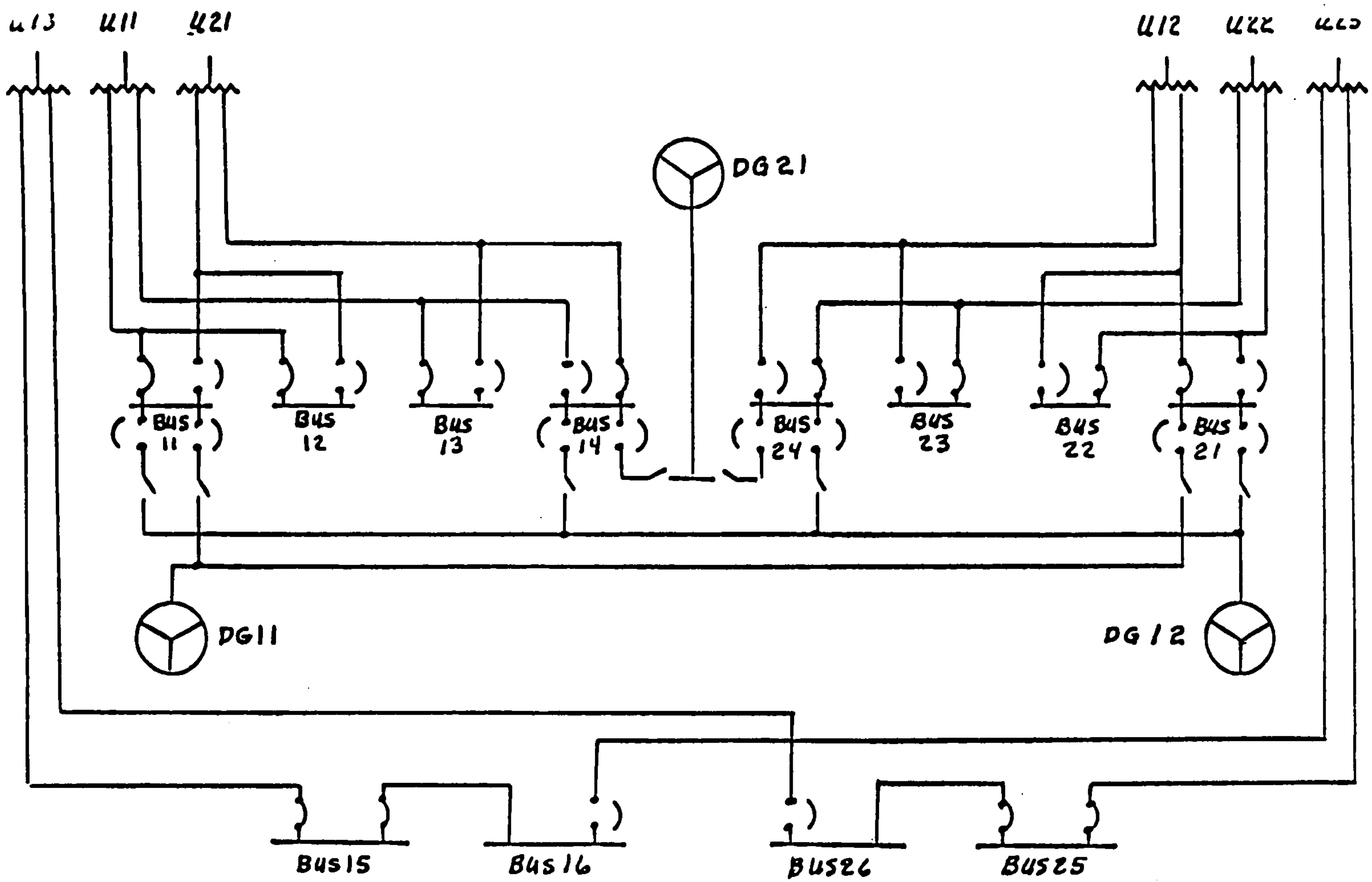


Fig. B21. 4.16 kV distribution.

22, 23, 24, 25, and 26)--six per unit. Two of the 4160-V buses for each unit (11 and 14 for Unit 1, 21 and 24 for Unit 2) supply power to the engineered safety features (ESF). The two ESF buses in each unit feed identical and redundant ESF equipment, and can be supplied from separate emergency diesel generators (DG-11, 12 or 21).

The 4160-V buses are metal-clad switchgear assemblies with draw-out air circuit breakers. Relay protection, ground connections, and structural safeguards are provided to assure adequate personnel protection and to prevent or mitigate equipment damage during system fault conditions. Dc control power is required for remote control and operation of the protective relays for the 4160-V circuit breakers. With loss of dc control power, the breaker cannot be operated remotely and all relay protective functions are inoperable, but the breaker can be tripped by manually pushing the trip lever located on the breaker. The breaker can be closed manually by pushbutton on the breaker when the closing spring is fully charged, but because the breaker trip relays would not be operable an operator would be very cautious about closing the breaker without dc power.

With the exception of the non-Class 1E feeder to the south service building, all 4160-V feeder breakers can be operated from the control room. Normally the feeders to buses 11, 12, and 13 are from unit service transformer U-4000-11; bus 14 from U-4000-21; bus 21 from U-4000-12; buses 22, 23, and 24 from U-4000-22; buses 15 and 16 from U-4000-13; and buses 25 and 26 from U-4000-23. However, each bus has an alternate source for use when the normal source is not available. All bus transfers from normal feeders to alternate feeders and return transfers are manual. The only automatic transfer is from off-site power to diesel generators after off-site power has failed.

The plant power system includes diesel generators (Fig. B22) that supply power to essential ESF equipment and to selected non-class 1E loads if the normal power supply is not available. The emergency power sources consist of three 4160-V, 3-phase, 60-Hz diesel generators rated at 2500-kW each. If one of the three diesel generators should fail to start or carry the load, the remaining two diesels have the capacity to power the required loads.

The diesel generators are started automatically by either a bus under-voltage or a SIAS; however, in the latter case, actual transfer to the bus is not made until the preferred source of power is lost. There are three control circuits, one for each of the diesel generators. During normal conditions with all three diesel generator units available, DG-11 is preselected to power bus 11, DG-21 is preselected to power bus 24, and DG-12 is set up to power bus 14 or 21.

Preselection of a diesel generator to power a given 4160-V bus is accomplished by closing the disconnect to the selected bus. The disconnects are key interlocked to prevent simultaneously connecting two

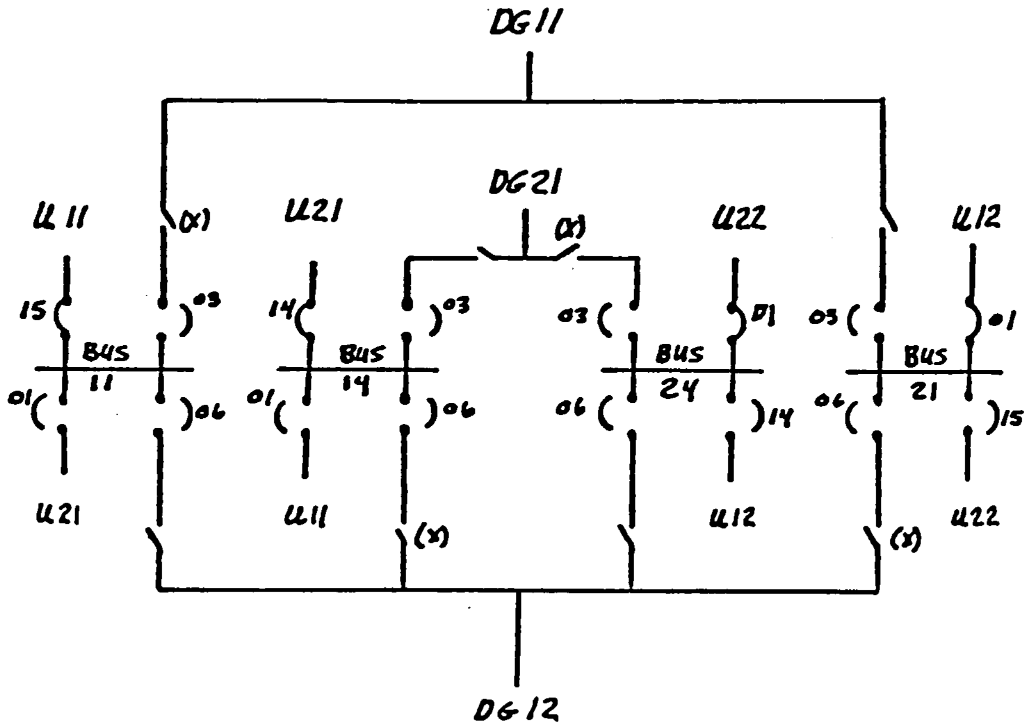


Fig. B22. Emergency power (ESF) 4.16 kV bus.

diesels to a single bus or simultaneously closing more than one disconnect of a single diesel generator, except DG-12 where closure of the disconnects for bus 14 and 21 is permitted.

The 480-V ac system (Fig. B23) consists of single-ended and double-ended unit load centers each supplied from a separate 4160/480-V unit service transformer. Four of the 480-V unit load centers for each unit (11A, 11B, 14A, and 14B for Unit 1; 21A, 21B, 24A and 24B for Unit 2) supply power to ESFs.

B.12.4 480-V System

The 480-V unit load centers consist of metal-clad switchgear with draw-out air circuit breakers. The motor control centers (MCCs) fed by the 480-V unit buses are metal enclosed with removable breaker and starter combination modules. Relay protection, ground connections, and structural safeguards are provided to assure adequate personnel protection and to prevent or mitigate equipment damage during system fault conditions. The 480-V loads are protected by the amptector solid state trip device that receives its actuating energy from the sensors and supplies a pulse of tripping current to a direct trip device. These devices do not require dc power to trip the breaker on a fault condition. However, the 480-V breakers that can be operated remotely require dc for remote operation.

The 480-V buses of particular interest to this program are reactor MCC 104R and reactor MCC 114R. These two MCCs power the 120-V ac instrument buses and also power the pressurizer PORVs and the pressurizer PORV isolation valves. MCC 104R is in Class 1E division ZB, and MCC 114R is in Class 1E division ZA. MCC 104R supplies instrument bus 1Y10 and MCC 114R supplies instrument bus 1Y09.

B.12.5 250-V dc Emergency Pump System

The 250-V dc emergency pump system is designed to supply power to the backup lube oil and seal oil pumps in case of loss of auxiliary ac power or failure of the normal ac pumps. The 250-V dc emergency pump system consists of one 250-V bus, one battery, and two battery chargers. One battery charger is powered from 480-V unit bus 11A and the other from 480-V unit bus 21A.

The 250-V dc emergency pump system is incapable of continually supplying all connected loads. It can power the largest connected load when operating in the designed state. It does have the capacity for orderly shut down of the main and feedwater turbines without ac power.

Failure of the system to provide emergency lubricating and seal oil could result in turbine damage, which affects the regulating system response only if the main feedwater pumps are required for shutdown heat removal.

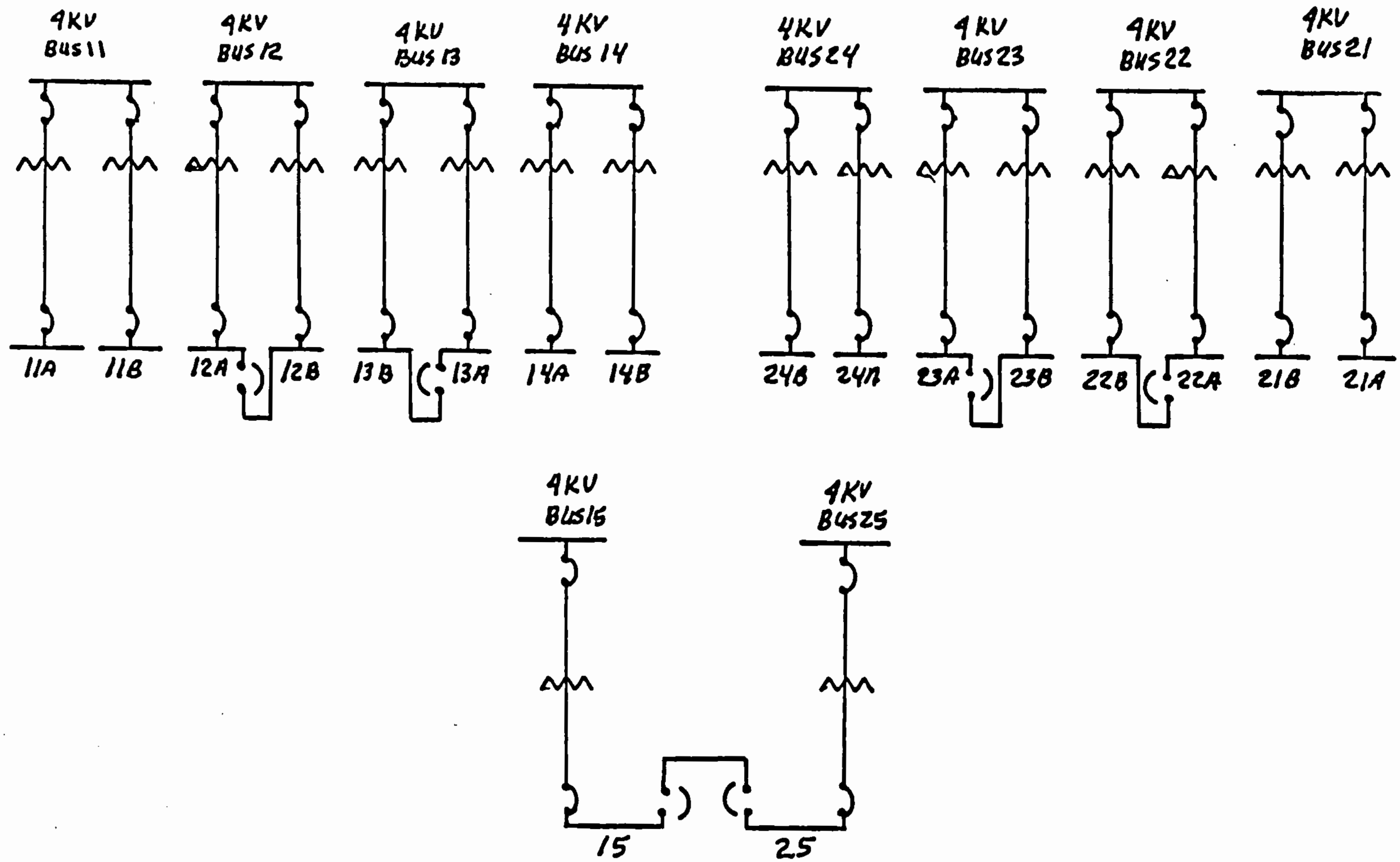


Fig. B23. 480 V distribution.

B.12.6 125-V dc I&C System

The 125-V dc and 120-V vital ac systems (Fig. B24) for the plant are divided into four independent, isolated channels. Each channel consists of one battery, two fully rated battery chargers, one dc bus, multiple dc unit control panels, and two inverters. Each inverter has an associated vital ac distribution panelboard. Power to the dc bus, dc unit control panels, and inverters is supplied by the station batteries or one or both fully rated battery chargers. One battery charger for each bus is supplied from an MCC in Unit 1 and the second charger from MCC in Unit 2. The sources of 125-V dc control power for the various distribution buses are listed in Table B3.

A reserve 125-V dc system for the plant is completely independent and isolated from all four channels, yet is capable of replacing any of the 125-V batteries. This system consists of one battery, one battery charger, and associated dc switching equipment.

The 120-V vital ac system provided for each unit has four separate distribution panelboards that provide power to the four reactor protection system channels and the four ESFAS channels. Each panelboard is supplied by an inverter with its own dc feeder from a separate battery and can be manually switched from the inverter to a 120-V ac back-up bus (one for Unit 1 and one for Unit 2) fed from an ESF MCC through a regulating transformer. Interlocks are provided on each inverter manual transfer switch to ensure that each back-up bus will have no more than one vital bus connected to it. Vital buses 1Y01 and 1Y02 provide power to some of the reactor regulating systems in Unit 1. These control systems and their power sources are identified in Appendix D.[10]

B.12.7 120-V ac Instrument Power

The 208-120-V ac instrument system is designed to furnish power to all plant instruments other than those supplied from the dc and vital ac systems. The ac instrument system for each unit is divided into two panelboard sections, 1Y09 and 1Y10, each supplied by a single three-phase transformer connected to an ESF MCC. The two instrument panelboards are connected through two normally open disconnects. The control systems powered by these instrument buses are identified in Appendix D.

B.13 INSTRUMENT AIR SYSTEM

The purpose of the instrument air (IA) system is to provide dry, oil-free air as needed throughout the plant for pneumatic valves, instruments, and controls.

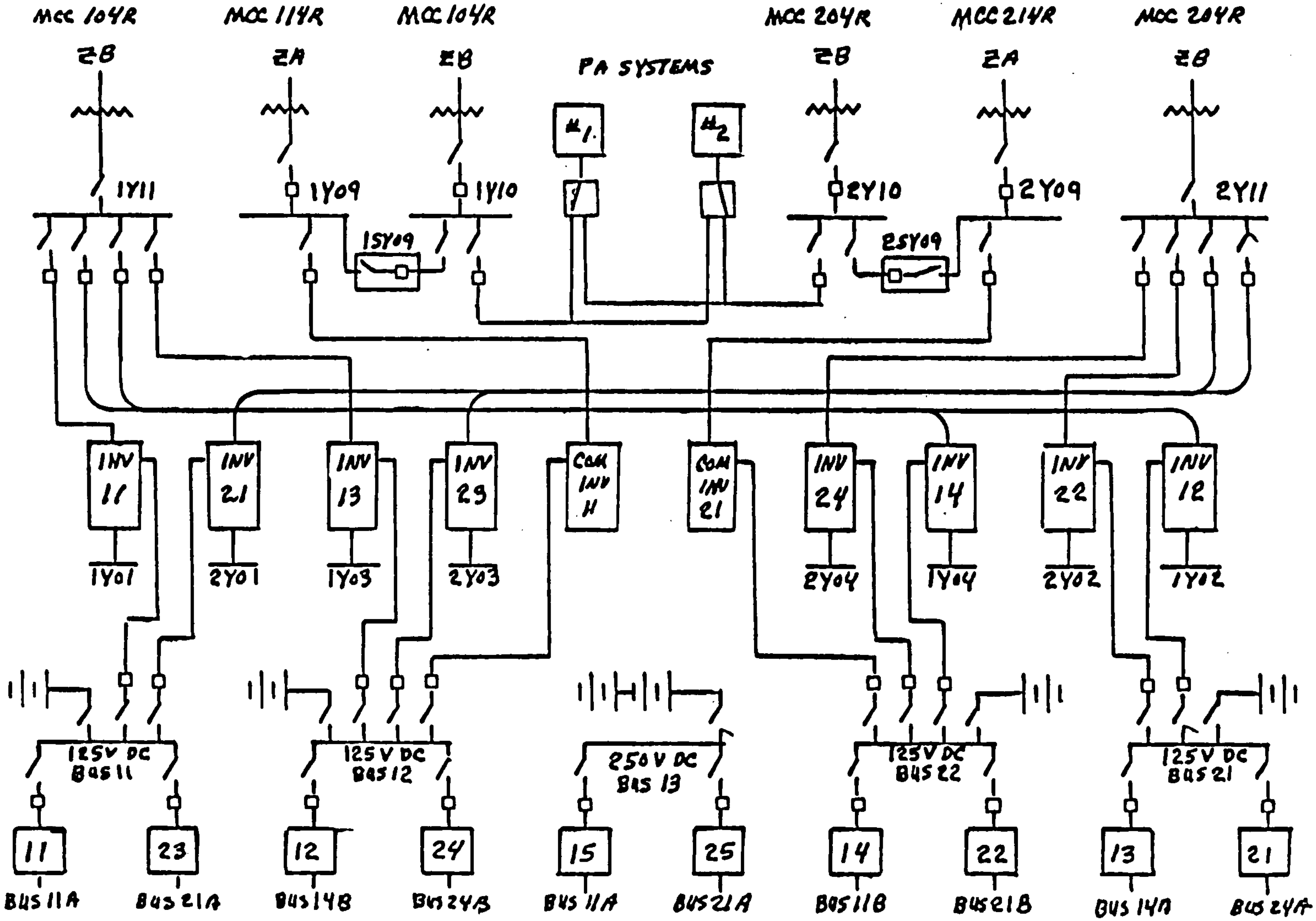


Fig. B24. 125-V dc and 120-V ac systems.

Table B3. 125-V dc breaker control panel.

13.8-kV Distribution System

Bus 11	DC11-14	DC12-3	Bus 21	DC25-14	DC26-3
12	DC12-4	DC13-14	22	DC26-4	DC27-4
11P	DC11-13	DC12-1	23	DC26-12	
12P	DC12-2	DC13-13	21P	DC21-3	DC22-1
13P	DC15-3	DC16-1	22P	DC22-2	DC23-24
14P	DC16-2	DC17-20	23P	DC25-13	DC26-1
			24P	DC26-2	DC27-13

4.16-kV Distribution System

Bus 11	DC11-15	DC12-5	Bus 21	DC12-13	DC22-13 ALT DC21-15
12	DC11-16	DC12-6	22	DC21-16	DC22-4
13	DC15-15	DC16-3	23	DC25-15	DC26-5
14	DC15-16	DC26-14 ALT DC16-4	24	DC25-16	DC26-6
15	DC12-7	DC13-15	25	DC25-23	DC26-13
16	DC12-14	DC13-16	26	DC25-24	DC26-7

480-V Distribution System

Bus 11A	DC11-17	DC12-9	Bus 21A	DC21-17	DC22-7
11B	DC12-10	DC13-17	21B	DC22-8	DC23-17
12A	DC11-18	DC12-11	22A	DC21-18	DC22-9
12B	DC12-12	DC13-18	22B	DC22-10	DC23-18
13A	DC15-17	DC16-6	23A	DC25-17	DC26-8
13B	DC16-8	DC17-17	23B	DC26-9	DC27-17
14A	DC15-18	DC16-7	24A	DC25-18	DC26-10
14B	DC16-9	DC17-18	24B	DC26-11	DC27-18
15	DC11-19	DC12-8	25	DC21-19	DC22-6

Each nuclear unit at Calvert Cliffs has a compressed air system that supplies both instrument and plant air for that unit. The compressed air system for each unit can be divided into four components: IA supply, plant air supply (which also serves as the backup supply for IA), IA distribution network, and plant air distribution network. The plant air portion of the compressed air system is of no interest to this study and will not be considered further except as it serves to back up the IA system.

Instrument Air Supply

Figure B25 shows the major components of the IA supply for Calvert Cliffs Unit 1. (The discussion in this report is for Unit 1; however, the Unit 2 IA system is almost identical to Unit 1.) On Fig. B25,

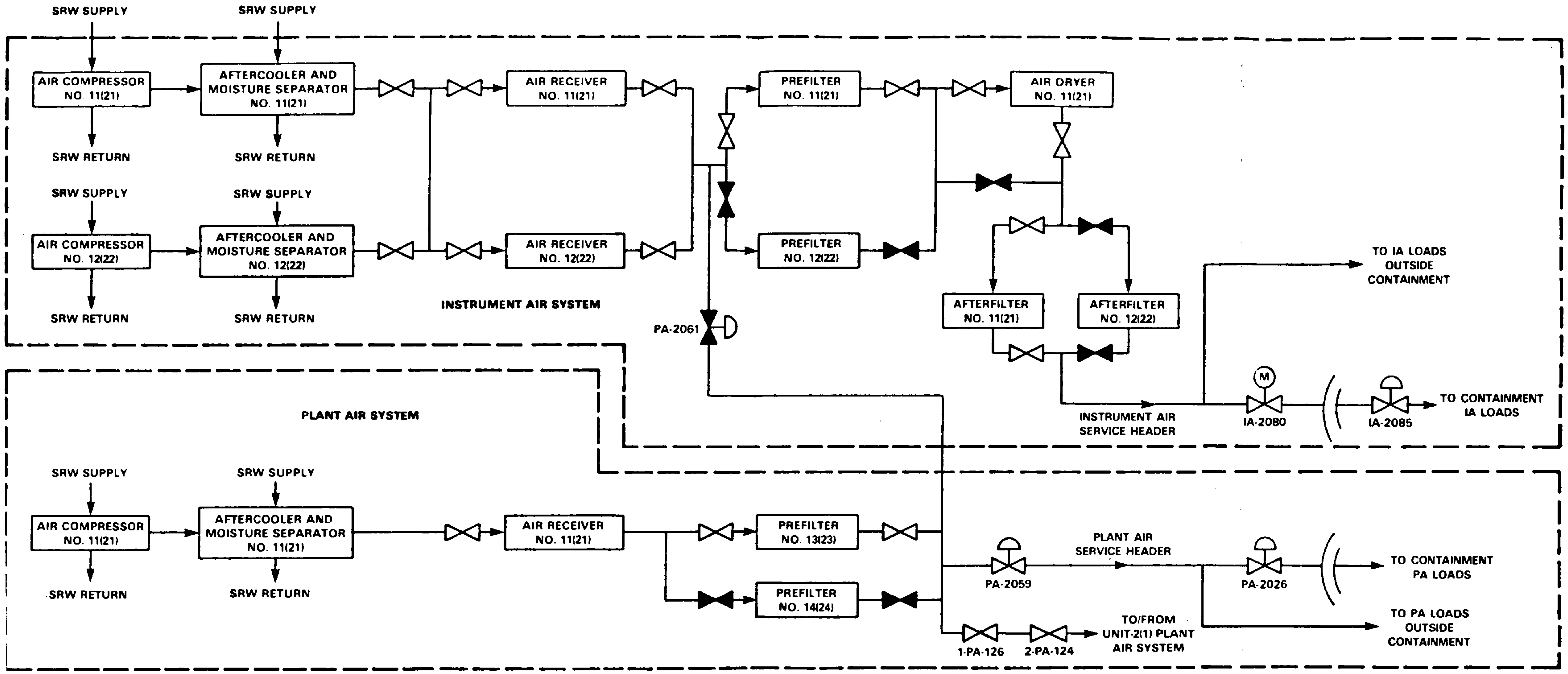


Fig. B25. Compressed air system simplified diagram.

numbers appropriate to Unit 1 are shown; Unit 2 numbers are shown in parenthesis where they differ. Referring to Fig. B25, two Joy electric motor-driven compressors (compressors No. 11 and 12 for Unit 1 and 21 and 22 for Unit 2) provide the normal source of IA through two air intakes and silencers. Each compressor is rated at 470 scfm at 100 psig, and each is powered from a different 480-V ac electrical bus. Compressor No. 11 receives electric power from Unit Bus 11B(ZA), and compressor No. 12 receives power from Unit Bus 11B(ZB). Compressor No. 11 receives power for its controls from 208/120-V ac Distribution Panel No. 114, and compressor No. 12 receives control power from 208/120-V ac Distribution Panel No. 14. Figure B26 shows the power distribution wiring for the IA system.

Each of the two IA compressors can be placed in either the SPEED, AUTO, or OFF operating mode. In the SPEED mode, the compressor acts to maintain IA pressure between 93 and 100 psig. In the SPEED mode, the IA compressor runs continually at a constant speed; however, the normal demand by the IA system does not require continuous operation of an IA compressor. Consequently, the IA compressor functions in two different cycles during SPEED mode of operation. In the loading cycle the compressor increases IA pressure from 93 to 100 psig. When IA pressure reaches 100 psig, the compressor goes into the unloading cycle, during which the compressor first-stage inlet is isolated and the second stage is vented. Internal air is pumped out and a vacuum is drawn inside the compressor. IA system pressure is allowed to decrease from 100 to 93 psig due to IA system demand. When IA pressure drops to 93 psig, the compressor shifts once again to the loading cycle and IA pressure is increased from 93 to 100 psig.

In the AUTO (or standby) operating mode, an IA compressor normally does not run; however, if IA pressure drops to 90 psig, the compressor will automatically start, and after an 18-s delay it will be automatically loaded and an attempt made to restore IA pressure. During normal plant operation only one IA compressor is required; therefore, one of the IA compressors will be in the SPEED mode and the other will be in the AUTO mode, ready to start and provide air if a problem develops.

Both compressors are cross-connected at their discharges by 6-in. lines to aftercoolers and moisture separators. The aftercoolers cool the compressed air leaving the compressors by means of a heat exchanger, which is cooled by flow from the service water (SRW) system. The cooling effect of the aftercooler causes moisture to condense in the aftercooler air. This moisture is removed by the moisture separators.

Cooling water flow is provided to the compressed air system through SRW valve 1628. After the cooling flow passes through valve 1628 (which controls SRW pressure to 55 psig), it splits into six parallel flow paths that provide cooling flow to the two IA compressors and their two aftercoolers. The other two branches provide cooling flow to the PA compressor and its aftercooler.

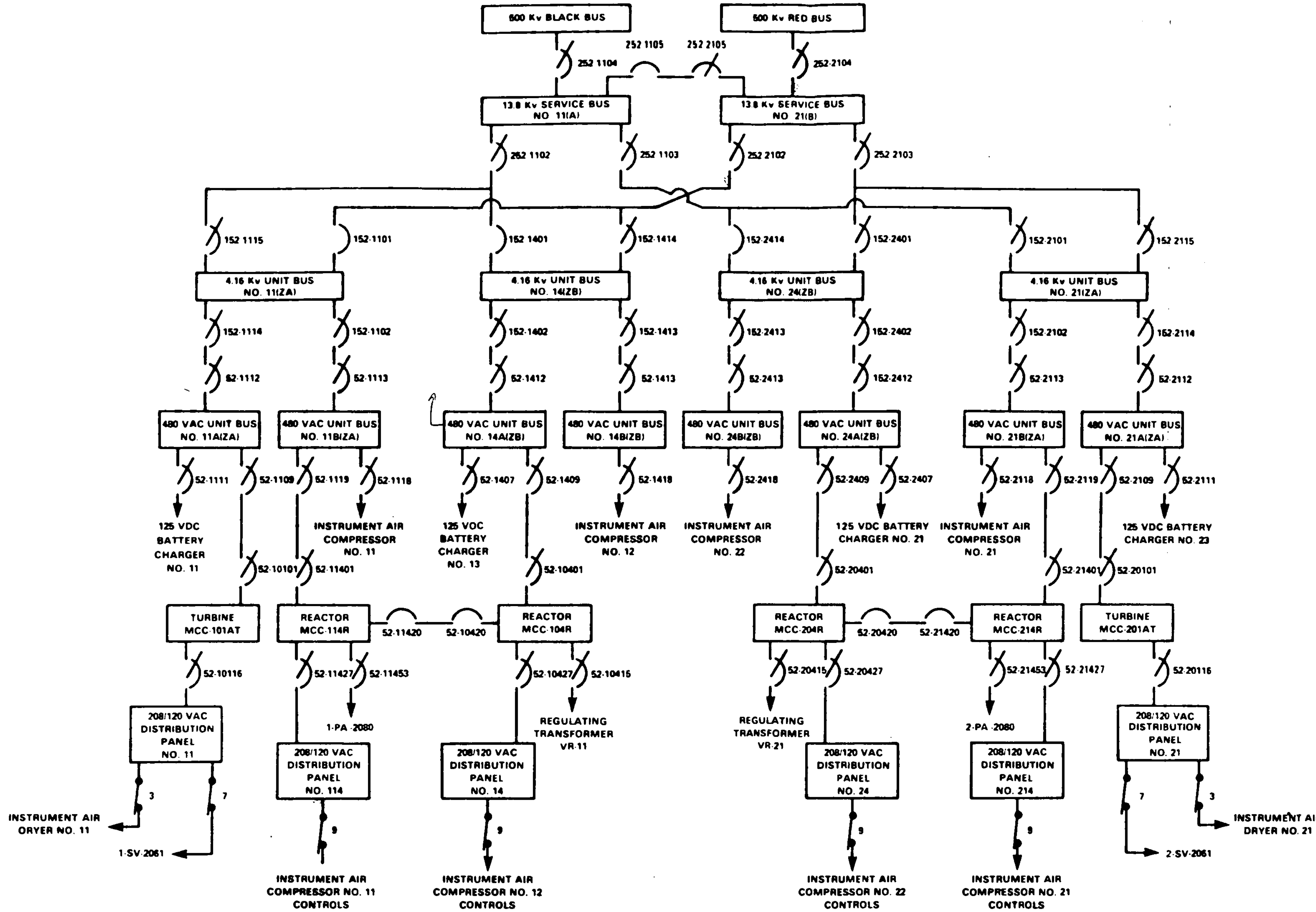


Fig. B26. Instrument air system power distribution.

From the aftercoolers/moisture separators, air flows to two 96-ft^3 air receivers that serve as air storage tanks to dampen system pressure variations. Each receiver is equipped with a safety relief valve that opens to relieve pressure greater than 115 psig. The two receivers are normally cross-connected but can be isolated at both their inlets and outlets by manual valves. Four-inch lines connect the receivers to a common header.

After leaving the air receivers, air enters two prefilters that remove oil, moisture, and particulate matter to prevent overloading the desiccant in the IA dryers. The two prefilters are in parallel and normally one is isolated and the other in operation. Both prefilters can be isolated by manual valves in their inlet and outlet lines. From the prefilters, air passes to the IA dryer. The dryer is an automatic, self-regulating unit that dehydrates the IA with a desiccant material, thus helping prevent corrosion in downstream piping and system loads. A bypass line around the dryer allows continued operation of the IA system if the dryer is out of service.

The last components in the IA supply network are two afterfilters. These units remove very small particles from the IA that might still be present after air passes through the dryer. During normal system operation, only one afterfilter is in operation and the other is in standby. Each aftercooler can be isolated by manual valves in its input and output piping.

Instrument Air Distribution Network

Once air leaves the aftercoolers, it enters the 4-in. IA distribution header. From this header, a number of branch lines supply instrument air to leads located throughout the plant. Figures B27-B29 show these branch lines and the major locations by blocks that they serve. A diverse collection of valves, instruments, and controls is served by the IA system in each block.

Plant Air Supply

Figure B25 also shows the major components of the plant air (PA) supply at Calvert Cliffs Unit 1. An identical, redundant plant air system exists for Unit 2. Referring to Fig. B25, note that the plant air supply has one air compressor. The compressor is rated at 616 scfm at 100 psig and is produced by the Joy Manufacturing Company. The compressor is powered by 480 V ac from electrical bus No. 14A(ZB). Compressor controls are powered from 208/120-V ac distribution panel No. 14.

The PA compressor provides compressed air at 100 psig and discharges it to the aftercooler/moisture separator. There the compressed air is cooled and entrained moisture is removed. The aftercooler and compressor are cooled by parallel flow paths from the service water. From the aftercoolers/moisture separators, air flows to a 96-ft^3

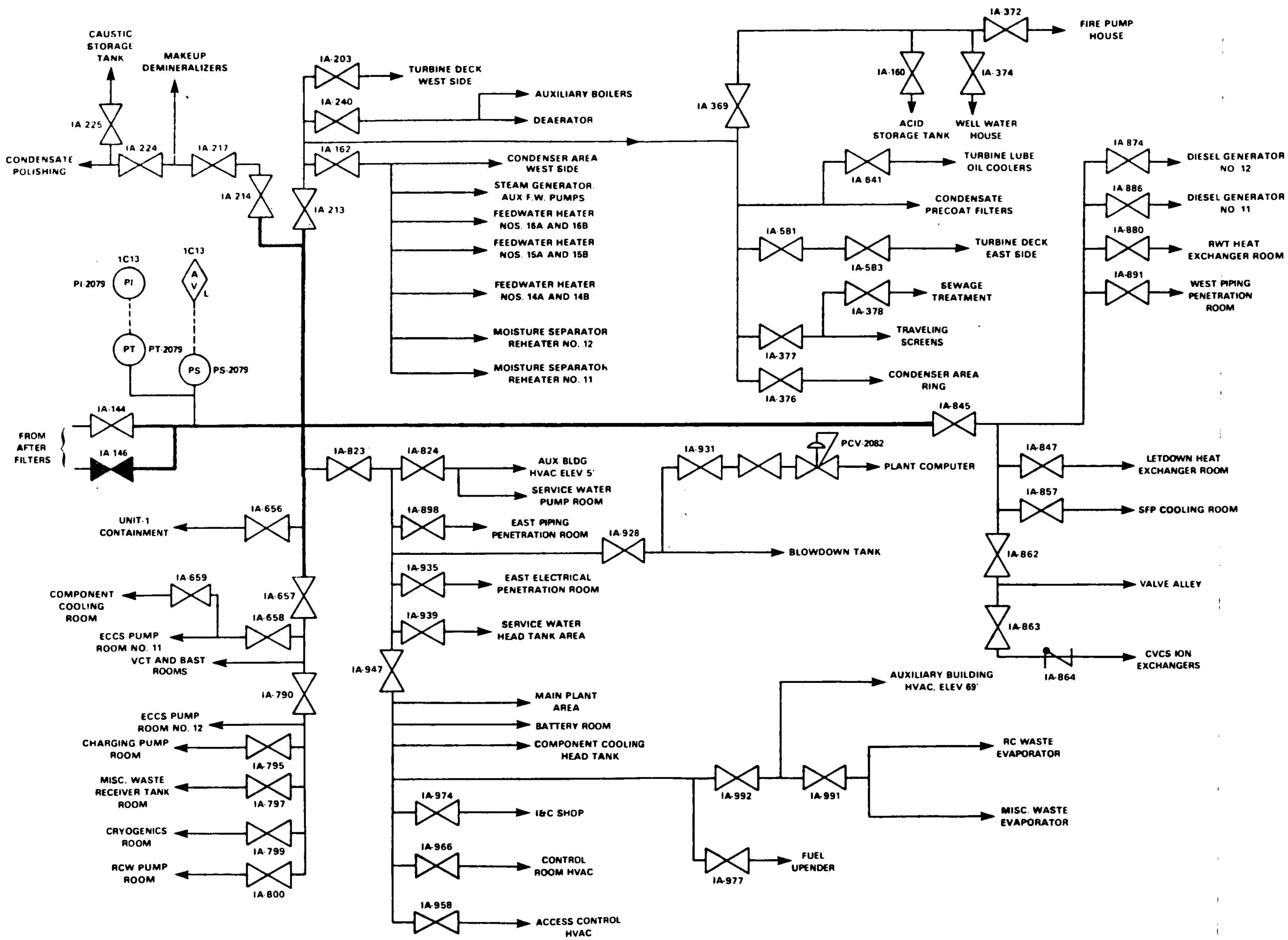


Fig. B27. Unit 1 instrument air distribution system.

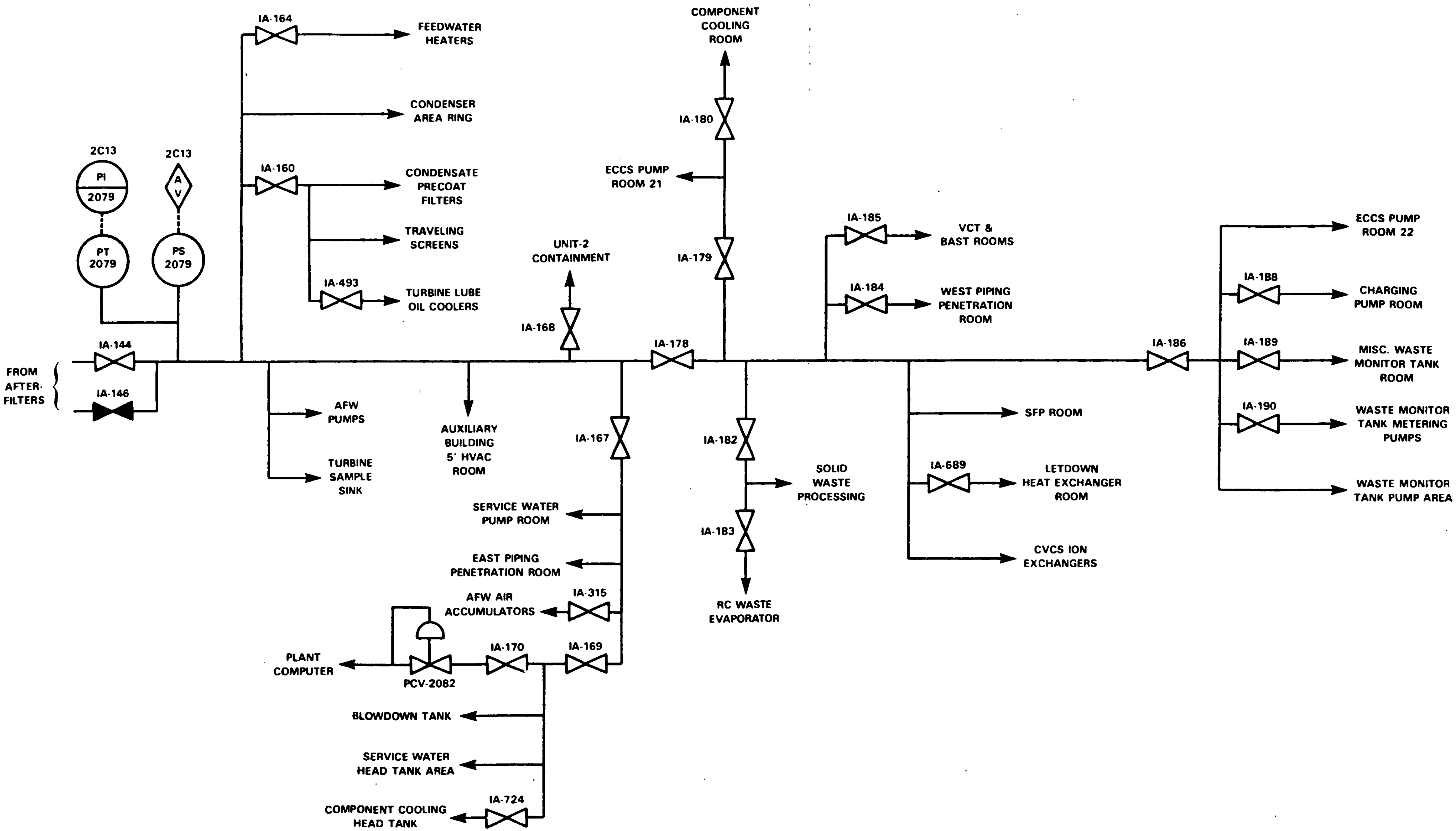


Fig. B28. Unit 2 instrument air distribution system.

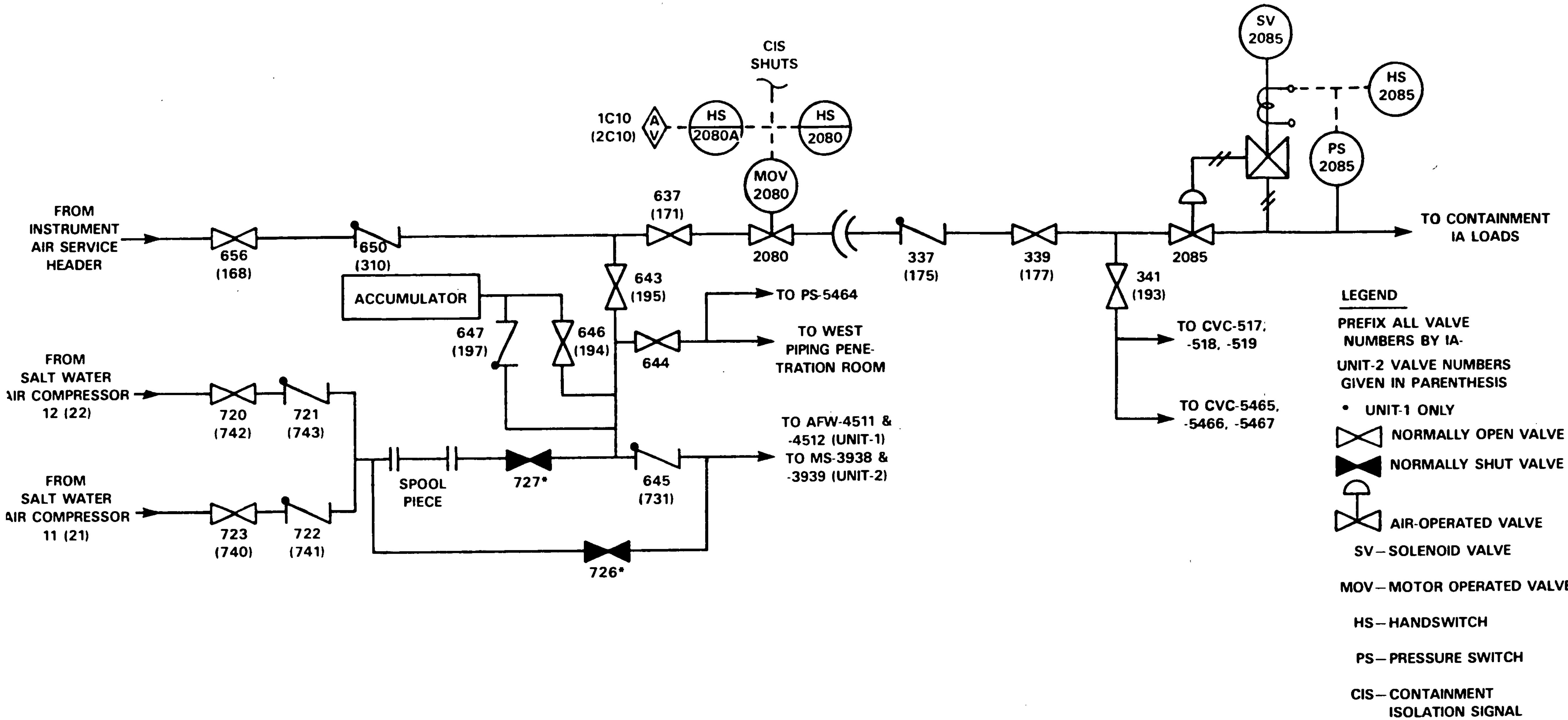


Fig. B29. Instrument air system diagram.

receiver that serves as an air storage tank to dampen system pressure variations. The receiver is also equipped with a safety relief valve that opens when PA pressure exceeds 115 psig.

After leaving the receiver, air enters two prefilters that remove oil, moisture, and particulate matter to prevent contamination of PA system piping and loads. The two prefilters are arranged in parallel in the PA system flow path. During normal operation, only one prefilter is in operation and the other is isolated in a standby condition.

At the outlet of the PA prefilters, air enters the PA service header. From the service header, PA is provided throughout the plant to various outlets for breathing air stations inside containment, to service outlets for compressed air for tools and cleaning, and for other miscellaneous uses throughout the plant.

During normal operation Unit 1 and Unit 2 PA Systems are cross-connected by opening manual valves PA-126 and PA-124 as shown in Fig. B25. Either Unit 1 or Unit 2's PA compressor will be running (in the SPEED mode) and the other unit's compressor will be in the AUTO (or standby) mode. The two PA compressors will then operate in a manner identical to operation of the two IA compressors discussed earlier. That is, the compressor in the SPEED mode will load and unload to maintain PA pressure between 93 and 100 psig. If PA pressure drops to 90 psig, the PA compressor in the AUTO (or standby) mode will start and attempt to restore PA pressure to normal.

Instrument Air Backup

The PA compressors serve the additional duty of backing up the IA supply system in the event IA pressure drops abnormally low. This occurs in the following manner. The IA and PA systems can be automatically cross-connected by opening valve PA-2061 (see Fig. B25). This valve is set to open automatically if IA pressure drops to 85 psig; also, at 85 psig valve PA-2059 closes automatically, thus isolating the PA compressors from their normal loads and making all of the air they compress available to the IA system.

A brief example of the sequence of events that occurs on falling IA pressure will illustrate operation of the PA compressors to back up the IA compressors. Suppose the following condition exists in Unit 1: IA compressor No. 11 is in SPEED mode, loading and unloading to maintain IA pressure between 93 and 100 psig; IA compressor No. 12 is in the AUTO mode; PA compressor No. 11 is in the SPEED mode, loading and unloading to maintain PA pressure between 93 and 100 psig; PA compressor No. 21 (in Unit 2 PA system) is in the AUTO mode; valves PA-126 and PA-124 in Fig. B25 are open to cross-connect the Unit 1 and Unit 2 PA systems; PA-2061 is closed so that the PA and IA systems are isolated.

Given the above conditions, suppose that a supply line in the IA header develops a leak and IA pressure begins to drop. When IA pressure drops below 93 psig, IA compressor No. 11 will be continually in the load mode. When IA pressure drops to 90 psig, IA compressor No. 12 will auto start and 18 s later load itself to help restore correct pressure. If IA pressure continues to fall, at 85 psig valve PS 2061 will automatically open to cross-connect the IA and PA systems. Opening PA 2061 should result in at least a temporary increase in IA pressure since the PA distribution header pressure will be at 93 psig or greater. At this point both IA compressors are operating and PA compressor No. 11 is operating to maintain pressure in the cross-connected IA/PA system. Suppose, however, that air pressure continues to decrease. At 90 psig PA compressor No. 12 in Unit 2 will auto start and load itself. If PA/IA pressure drops to 85 psig, valve PA-2059 will automatically close to isolate the PA header. When valve PA-2059 closes, note that a total of four air compressors (two IA and two PA compressors) are running and supplying compressed air to the IA distribution header.

REFERENCES FOR APPENDIX B

1. "Reactor Coolant System, System Description No. 5," BG&E Calvert Cliffs Nuclear Power Plant, July 1983.

2. "Final Safety Analysis Report, Baltimore Gas and Electric Calvert Cliffs Nuclear Plant," December 1980.

3. "Chemical and Volume Control System, System Description No. 6," BG&E Calvert Cliffs Nuclear Power Plant, September 1982.

4. "Main Feedwater System, System Description No. 32," BG&E Calvert Cliffs Nuclear Power Plant, November 1982.

5. "Condensate System, System Description No. 29," BG&E Calvert Cliffs Nuclear Power Plant, August 1982.

6. "Main Steam and MSIV System, System Description No. 19," BG&E Calvert Cliffs Nuclear Power Plant, June 1983.

7. "Component Cooling System, System Description No. 40," BG&E Calvert Cliffs Nuclear Power Plant, October 1983.

8. "Service Water System, System Description No. 39," BG&E Calvert Cliffs Nuclear Power Plant, November 1982.

9. "Salt Water System, System Description No. 38," Calvert Cliffs Nuclear Station, revised May 14, 1976.

10. C. W. Mayo et al., "Failure Modes and Effects Analysis (FMEA) of the Regulating Systems Electric Power Distribution Circuitry at the Calvert Cliffs Unit 1 Nuclear Plant," Science Applications International Corporation, December 1984.

APPENDIX C

DETAILED FMEAs

Preliminary failure mode and effects analyses (FMEAs) were performed on all systems selected for analysis as a result of the work described in Appendix A. For completeness of documentation, the entire record of these FMEAs is provided in the following pages. The majority of this effort led to low consequence outcomes; the few cases not bounded by previous analyses are treated in detail in Chapters 4 through 6 in Vol. I of this report.

Table C1. Reactor coolant system FMEA

Failure/Component	Possible Causes	Effects	Remedial Actions
Reactor Vessel			
1. Undetected Noncondensibles Collect in the Reactor Vessel	1. Fuel Damage 2. Corrosion Products	Reduced heat transfer from RCS to steam generator. Potential undercooling.	Detect poor heat transfer with axial flux monitors (?). Detect fuel damage with process activity monitor in CVCS.
2. Vent Valves (RC-103-SV and RC-104-SV) Fail Open	1. Operator Error 2. Inadvertent Signal from Control Board	Small LOCA. Reactor coolant discharges to quench tank. System pressure drops and pressurizer level drops. Low pressure reactor trip occurs at 1875 psig and on high containment pressure if (when) quench tank blows down. Safety injection actuates at 1600 psig.	Ensure reactor is tripped and follow LOCA emergency procedures.
Steam Generator (SG)			
3. SG Tubes Rupture	1. Adverse RCS or SG Water Chemistry 2. Loose Parts	Reactor coolant (RC) leaks to secondary side of the SG and to the environment via atmospheric steam dump or SG safety valves. Depressurization of the RCS would be similar to a LOCA of equivalent size.	Follow SG tube rupture emergency procedures.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
4. Primary Head Divider Plate Between Inlet and Outlet Plenum Fails	1. Stress Corrosion Cracking 2. High Temperature or Pressure Differential Induced Failure	RC flow through U-tubes in SG is partially bypassed resulting in decreased heat transfer from primary to secondary side. Partial RCS undercooling will result. Other SG still provides heat removal. PORVs and safeties may open if temperatures rise drives pressure high enough. SG level may initially rise but then return to its setpoint. RCS pressure will be too high for normal SI, except for 132 gpm provided by the CVCS.	Trip reactor if not already tripped. Ensure operability of all three charging pumps in CVCS for needed makeup, cooling, and emergency boration.
<u>Reactor Coolant Pumps</u>			
5. Reactor Coolant Pump(s) Fail	1. Loss of AC Power 2. Trip of One or More 13 kV RCP Bus Feeder Breakers 3. Loss of Component Cooling Water 4. Fault in Pump or Motor	Reduction of coolant flow rate through the core and SG's. Increased possibility of core boiling. Pump seizure will result in faster flow rate reduction whereas failure due to power loss will be slower due to coastdown flow. Reactor will trip on low reactor coolant flow (95% of full flow).	Trip reactor if not already tripped. Perform actions to assist natural circulation cooldown, which include: boration from the CVCS, RCS inventory control with the CVCS or HPSIS, maintenance of RCS pressure with pressurizer heaters and auxiliary spray or charging pumps, and RCS heat removal by manual control of turbine bypass and atmospheric dump valves.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
6. Reactor Coolant Pump(s) Fail to Trip on Demand	1. Loss of Control Power 2. Operator Error 3. Faulty Trip Relays	The operator is required to trip the RCP's in the event of a LOCA. If the operator fails to trip them, more RCS inventory will be released through a hot leg break. The increased rate of coolant loss may be important to recovery from LOCA's depending on break size. Also, containment isolation isolates CCW to the RCPs and an RCP from seal failure may result if the pumps continue to operate. Containment isolation is initiated on high containment pressure (2/4 transmitters) or could be initiated inadvertently. The effect of this additional loss of coolant is expected to depend on break size.	Attempt to manually trip pump breakers.
7. RCP Seal Failure	1. Loss of CCW 2. Seal Component Damage from Debris in System or from Wear	Seal failure LOCA.	Trip reactor and RCPs. Follow emergency procedures for LOCA.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
	3. Integral Impeller Damage (auxiliary impeller for seal water intake or seal water recirculating impeller) 4. Seal Area Recirculating Pump Fails (to deliver water to the integral heat exchanger)		
Pressurizer			
8. Pressurizer Backup Heaters Fail to Energize on Demand	1. Loss of Supply Power 2. Control Signal Failure (level transmitter fails low) 3. Mechanical Failure 4. Control Handswitches in "OFF" Position (operator error)	If demanded due to decreasing pressure in the pressurizer, decrease continues without abatement and reactor eventually trips. Development of possible voids in the core. If demanded due to high level in pressurizer (i.e., loss of letdown flow or loss of power to pressurizer control components), level may continue to rise. Too much water volume in the pressurizer may damage the relief valves or the spray nozzles and degrade pressure de-	Maintain level in pressurizer with charging pump and letdown control valve control. For pressure maintenance, check that pressurizer spray is not actuating inadvertently and that proportional heaters are operating. Trip reactor if pressure approaches low pressure reactor trip setpoint.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
		crease control capability (less steam volume to condense with spray).	
9. Pressurizer Backup Heaters Fail to Trip on Demand or Inadvertently Energize	1. Control Signal Failure (level transmitter fails high, pressure transmitter fails low, etc.) 2. Control Handswitches Left in "ON" Position 3. Loss of Control Power	High pressure results in the pressurizer. If spray is actuated, net effect will be negligible. If pressure transmitter has failed low, spray will not operate. (Heaters can still trip if lo-lo level develops in pressurizer.) Resulting high pressure would normally open PORV and trip reactor. If reactor trips and pressurizer empties, possible damage to the pressurizer could occur. If level transmitter fails high, pressurizer will empty with heaters failed on, which may initiate a failure of the pressure boundary (small nonisolable LOCA).	Attempt to switch heaters to "OFF" position with handswitch or restore to "AUTO" if previously "ON". Manually operate pressurizer spray as required. Manually open breakers if required.
10. Pressurizer Spray Line (or Nozzles) Blocked	1. Corrosion Product Buildup 2. Loose Parts or Debris	High pressure surges in the pressurizer cannot be controlled. On power increase, a high pressure reactor trip and PORV opening may occur.	Turn off any backup pressurizer heaters that are energized. Trip reactor if not already tripped and repair component. Utilize auxiliary spray from CVCS as required.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
11. Pressurizer Spray Valves Fail to Open on Demand	1. Mechanical Failure 2. Control Signal Failure (Pressure control fails low) 3. Loss of Instrument Air and Accumulator Holding Check Valves Fail	Pressurizer spray is failed if both valves fail and is degraded if only one fails. On a power increase or pressure surge, a high pressure reactor trip and PORV opening may occur.	Same as above.
12. Pressurizer Spray Valves (RC-100E-CV and RC-100F-CV) Fail to Close on Demand. (Valves Fail Open)	1. Valve Stuck Open 2. Control Signal Failure	Spray flow into pressurizer continues. Maximum spray rate is 375 gpm. Spray does not add to pressurizer level due to surge volume outflow. Cooling from spray causes level increase and pressure decrease in pressurizer from condensation. Backup heaters energize in response to pressure drop, but cannot offset decreased enthalpy from spray addition. Low enough pressure in the pressurizer will initiate a reactor trip and an SIAS. The operator is required to trip the RCPs on SIAS, which will stop the spray flow and terminate the transient. If transient is caused by pres-	Trip reactor and RCPs if not already tripped. Repair component. Switch to alternate pressure regulating system (X or Y) if pressure transmitter or control has failed.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
		surizer pressure transmitter failed on the high side, low pressure RT and SIAS channels will be degraded.	
13. Spray Line Continuous Flow Bypass Valves (RC-219 and RC-220) Fail Closed	1. Valves Plugged from Corrosion or Debris in System 2. Operator Error in Setting 3. Valve Fault	Potential for thermal shock to pressurizer spray line and nozzles when spray is demanded. Potential non-isolable LOCA.	Failure may be hard to detect unless heat loss from stagnant line is detected at TE-103 and 104. Align auxiliary spray to provide bypass flow if CVC-517-CV can be set to low flow rate (1-2 gpm).
14. Spray Line Continuous Flow Bypass Valves (RC-219 and RC-220) Fail Open	1. Valve Fault 2. Operator Error in Setting	No significant effect. Increased flow through bypass line to pressurizer but line is only 3/4 in. dia.	Repair component at shutdown.
15. Auxiliary Spray Valve (CVC-517) Fails Open (this valve fails closed on loss of instrument air)	1. Valve Fault 2. Operator Error	Spray flow at 395°F is delivered to the pressurizer inadvertently. Maximum possible flow is 132 gpm, more probable flow is less than 44 gpm. No net gain in RCS inventory beyond that demanded by pressurizer level program. Some pressure decrease in the pressurizer and potential level drop from contraction. CVCS	Attempt to close valve. Monitor pressurizer pressure and trip reactor if pressure drop is too great. Repair valve at shutdown.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
		response to decreased level of adding charging flow will add more spray flow. Maximum probable 44 gpm at 395°F to pressurizer representing -94,500 Btu/min vs the heater capacity of +68,300 Btu/min.	
16. Vent Valves from Pressurizer (RC-105-SV and RC-106-SV) Inadvertently Open	1. Operator Error 2. Inadvertent Signal from Control Board	Small LOCA. Steam from the pressurizer is discharged to the quench tank. Pressurizer pressure drops. Level and temperature also drop in pressurizer due to increased vaporization of the reactor coolant. RCS pressure drops consistent with pressurizer pressure and slight contraction in RCS occurs (approximately 1 vol. % for 600 psid). Low pressure reactor trip should occur at 1875 psig, SIAS at 1600 psia and charging flow on low pressurizer level. Pressurizer may empty from reactor trip.	Close vent valves. Trip reactor if not already tripped. Ensure heaters are de-energized to prevent pressurizer damage.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
Power Operated Relief Valves (PORVs)			
17. PORV(s) Fail Open (RC-402-ERV and/or RC-404-ERV)	1. Valves Fail to Close After Demanded to Open 2. Operator Error 3. Control Signal Failure 4. Valve(s) Leak	Same as above (small LOCA). PORVs normally open with high pressure reactor trip, so reactor trip will have probably occurred.	Attempt to close motor operated PORV block valves (RC-403-MOV and/or RC-405-MOV). Follow appropriate emergency procdures for a small LOCA.
18. PORV(s) Fail to Open on Demand	1. Control Circuit Failure 2. Mechanical Failure 3. Loss of Electric Power Supply 4. Block Valves Closed Due to Leaking PORVs	Code safety valves will open on high pressure if the PORVs fail. However, during a LOCA, the RCS cannot be depressurized to prevent PTS conditions as required by procedure. In addition, the PORV's would be unavailable to enhance post-LOCA RCS depressurization and net HPSI flowrate.	Shutdown and repair component(s).
19. PORV Isolation Valves Inadvertantly Closed on Demand	1. Operator Error 2. Valves Closed Due to Leaking PORVs.	Code safety valves will open on high pressure demand if the PORVs are blocked.	Open valves.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
20. PORV Isolation Valves Fail to Close on Demand	1. Operator Error 2. Valve Fault 3. Loss of Electric Power Supply	These are demanded to close when PORVs fail open. Remote potential for small LOCA as described for PORVs failing open. However, potential is remote since multiple failures are required and each isolation valve has a vital power supply separate from the power supply for its associated PORV.	Ensure reactor is tripped and pressurizer heaters are de-energized. Follow emergency procedures for small break LOCA event.
<u>Code Safety Valves</u>			
21. Code Safety Valves Fail to Open on Demand	1. Valve Fault (calibration, damage)	If PORV path fails to open on demand (high pressure conditions), these valves are demanded. RCS under-cooling and potential for large break LOCA from vessel rupture.	Attempt to open PORV path. Trip reactor if not already tripped.
22. Code Safety Valve(s) Fail Open	1. Valve Fault (calibration, damage)	Small LOCA. Pressurizer steam discharges to the quench tank. Low pressure reactor trip occurs and pressurizer may empty. SIAS will be initiated at 1600 psig.	Follow emergency procedures for small LOCA. Ensure reactor has tripped.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
Quench Tank			
23. Drain Valve to RCDT (RC-401-CV) Fails Open or Leaks	1. Mechanical Failure of Valve Resulting in Valve Opening or Failure to Close Once Open 2. Power to Solenoid Fails on from Control Board Handswitch Failure (HS-1401) 3. Operator Error or Action Based on Failed Level Indicator	Quench tank may empty. LIA-116 may also be on the same power supply as the failed valve and may fail to detect low tank level. When a pressurizer relief valve opens, the quench tank will relieve to the waste gas system through RV-242 (at 35 psig) or to containment through the rupture disk (at 100 psig), rather than absorbing the discharge from the pressurizer. Quench tank rupture may occur depending on the transient, if the (16 in.) rupture disk fails.	Attempt to close the valve and add demineralized water to quench tank via DW-5460-CV.
24. Relief Valve (RV-242) Fails to Open on Demand	1. Mechanical Failure of Valve 2. Error in Valve Setting During Maintenance	On demand (significant pressurizer discharge to quench tank). The quench tank relieves to the containment through the rupture disk rather than partially to the waste gas system. SI will be initiated from high containment pressure. SI may lead to pressurizer overfill from	Utilize relief valve bypass (RC-400-CV) at high tank pressures below rupture disk setpoint (100 psig) and verify operability of vent valve RC-402-SV.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
		charging pump initiation and letdown isolation.	
25. Relief Valve (RV-242) on Relief Bypass Valve (RC-400-CV) Fails Open	1. Mechanical Failure of Valve 2. Error in Valve Setting During Maintenance	Quench tank steam from pressurizer and entrained liquid may discharge to waste gas system below valve setpoint (i.e., unnecessary discharge). Not a significant effect.	Repair component at next shutdown.
26. Vent Valve (RC-402-SV) Fails Open	1. Operator Error 2. Inadvertent Signal from Control Board Fails Solenoid Power On	Quench tank steam from pressurizer and entrained liquid can discharge to containment. SI will be initiated from high containment pressure. TIA-102 will alarm at 300°F indicating steam discharge through vent valve. SI may lead to pressurizer overfill from charging pump initiation and letdown isolation.	Attempt to close valve. Shutdown and repair component if faulted.
27. Quench Tank Rupture Disk Fails Open	1. Improper Installation 2. Faulty Rupture Disk	Quench tank steam from pressurizer and entrained liquid can discharge to containment. SI will be initiated from high containment pressure. SI may lead to pressurizer overfill from	Check pressurizer conditions and block pressurizer flow if appropriate. Repair component after shutdown and transient is terminated.

Table C1. (continued)

Failure/Component	Possible Causes	Effects	Remedial Actions
		charging pump initiation and letdown isolation.	
28. Quench Tank Rupture Disk Fails to Open at Design Pressure	1. Improper Installation 2. Faulty Rupture Disk	Rupture disk is demanded to open at 100 psig (design pressure of quench tank). During transients, possible quench tank rupture. Reactor coolant release to containment. SI will be initiated. SI may lead to pressurizer overfill from charging pump initiation and letdown isolation.	Open relief valve bypass (RC-400-CV) to ensure partial relief to waste gas system. Check pressurizer conditions. Close PORV block valves if PORVs have failed open.
29. Fill Valve from Demineralized Water Storage Tank (DW-5460-CV) Fails Open or Leaks	1. Mechanical Failure of Valve Resulting in Valve Opening or Failure to Close Once Open 2. Operator Error or Action Based on Failed Level Transmitter 3. Power to Solenoid Fails on from Control Board Handswitch Failure (HS-5460)	Quench tank overfills. LIA-116 may also be on same panel as failed valve and may fail to detect high tank level. A pressurizer discharge transient may cause rupture disk to open prematurely, causing discharge to the containment and initiation of SI. SI may lead to pressurizer overfill from charging pump initiation and letdown isolation.	Attempt to close valve at panel. Open drain valve as required. Repair component after shutdown and transient is terminated if component is faulted.

Table C2. Chemical and volume control system FMEA

Failure	Possible Causes	Effects	Remedial Actions
<u>Letdown</u>			
1. Letdown Stop Valve (CVC-515-CV) or Letdown Containment Valve (CVC-516-CV) Fail Closed	1. Inadvertent or erroneous signal to close, including a. ESFAS (SIAS or CVCS isolation signal) b. High regenerative HX outlet temperature TIC-221 2. Loss of instrument air 3. Loss of control power to solenoid 4. Mechanical failure including plugging from loose parts	Letdown flow is stopped, including flow through the regenerative heat exchanger (HX), which usually heats charging flow. Unheated flow is delivered to the RCS. Pressurizer level will rise, which trips all but one charging pump and attempts to increase letdown flow via the letdown control valve (but letdown flow is isolated by the failure). With charging flow from the remaining pump at 44 gpm, RCS may overpressurize, causing the PORV to open.	After detecting failure, monitor pressurizer level and charging flow temperature (TE-229). Trip charging pump if level in pressurizer is too high.
2. Excess Flow Check Valve Fails Closed	1. Mechanical failure 2. Plugging	Same as above (loss of letdown flow).	Same as above.
3. Excess Flow Check Valve Fails Open	1. Mechanical failure	No effect if letdown control valves operate properly and if no rupture occurs between excess flow check valve and letdown control valves.	This failure will not be detected unless by inspection at shutdown or demanded by an abnormal event.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
4. Operating Letdown Control Valve (CVC-110P-CV or CVC-110Q--CV) Fails Closed	1. Loss of instrument air 2. Loss of solenoid control power 3. Mechanical failure 4. Control signal failure	Loss of letdown flow which also stops RCS flow through regenerative HX. Unheated charging flow at 44 gpm minimum is delivered to the RCS. Potential for RCS to overpressurize and the PORV to open if charging flow continues.	For both valves failing, isolating charging flow is required. If only one of the two valves fails, place the standby valve in service (requires manual alignment of valves).
5. Both Letdown Control Valves (CVC-110P-CV and CVC-110Q-CV) in Service with RCS Pressure Above 1500 psig	1. Operator error 2. Malfunction of valve selector switch (HS-110-1)	Potential thermal shock to CVCS with potential for pipe rupture downstream of control valves. Release limited by excess flow check valve to 210 +/- 20 gpm. Excess letdown flow will lower pressurizer level and cause backup charging pumps to start. Net RCS loss of 98 gpm.	Isolate one control valve.
6. Letdown Control Valves (CVC-110P-CV and CVC-110Q-CV) Fail Open	1. Mechanical failure 2. Failure of the bias control regulator on each valve 3. Erroneous control signal from pressurizer level regulating system	Excess letdown flow even though both backup charging pumps start on low pressurizer level. Net decrease in RCS inventory and pressurizer level (maximum letdown 230 gpm - maximum charging 132 gpm = 98 gpm) and high level alarm in volume control tank (VCT). Eventual	Close letdown stop valves.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		shift of VCT inlet from tank to waste processing system.	
7. Letdown HX Fails to Cool	1. Loss of component cooling water 2. HX damage	TE-224, on letdown outlet flow, will alarm, isolate the boronometer and radiation monitor and shift letdown flow to bypass the ion exchangers. If TE-224 fails, damage to monitors and ion exchangers could occur. Flashing of hot RCS fluid to steam is possible downstream of the letdown backpressure regulating valves, which would introduce steam into the VCT (via the normal spray inlet). VCT may become pressurized and relieve to the waste gas surge tank.	Assess boron concentration and activity in RCS based on data from before the event. Shutdown plant, if necessary, and repair HX or isolate letdown.
8. Operating Letdown Backpressure Regulating Valve (CV-201P or CV-201Q) Fails Open (normally fail closed on loss of air)	1. Pressure controller or transmitter (PT-201) fails high 2. Mechanical failure 3. Operator error	RCS fluid downstream of letdown control valve may flash to steam due to drop in line pressure. If fluid temperature is above 145°F, TE-224 should switch flow to VCT and bypass boronometer and radiation monitor. If temperature is below 145°F,	Isolate letdown. Check system flows and filter pressure drop to detect filter damage. If filter is not damaged attempt throttling of manual valves associated with one of the failed regulating valves. If failure is not caused by transmitter failure, place the

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		steam pockets may exist and damage monitors. High velocity flow may damage the purification filter and carry debris through the system, either blocking letdown flow or eventually failing the charging pumps.	standby regulating valve in service.
9. Letdown Backpressure Regulating Valves (CV-201P and CV-201Q) Fail Closed	1. Loss of instrument air 2. Pressure controller or transmitter (PT-201) fails high 3. Mechanical failure	Letdown flow is stopped, including flow through the regenerative HX. Pressurizer level will rise, backup charging pump will trip, but the main operating charging pump will continue to discharge to the RCS. RCS could overpressurize and cause the PORV to open, if charging flow continues. RCS charging flow will be colder than normal. VCT level will decrease and makeup flow will be delivered to the VCT (if makeup controller is in AUTO).	Monitor pressurizer level and RCS pressure. Trip charging pump, if necessary.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
10. Differential Pressure Indicator PDIS-202 fails to indicate and alarm plugged inservice filter, and In-service Purification Filter is Plugged (Normally Alarms at 30 psid)	1. For PDIS-202, mechanical failure or control power failure 2. For filter, accumulation of material not detected due to failed indicator	Reduced letdown flow, pressurizer level may rise and open letdown control valve more. Backpressure regulating valve will also open more, but flow will still be restricted. If upstream pressure reaches 205 psig, an upstream relief valve (354-RV) relieves line pressure to the reactor coolant waste receiving tank. Makeup water will eventually be required in VCT for charging pump suction. Failure results in a small loss of coolant out relief valve and cooler charging flow to RCS.	Detect PDIS failure prior to relief valve lift by low flow at FE-202, and after relief valve lift by high flow alarm (135 gpm). Put alternate filter in service or put 2" bypass line in service via CVC-124, and isolate plugged filter. Monitor flow closely with FE-202 to operate without PDIS-202.
11. Process Radiation Monitor Indicates Erroneous Fission Product Activity	1. Mechanical failure 2. High temperature damage from failure of signal from TE-224 and letdown cooling or failure of CVC-521, to close with failure of letdown cooling 3. Other support system failures	If monitor reading is low, high activity level could go undetected. No significant effect on undercooling. If monitor reading is high, purification and/or shutdown may be initiated unnecessarily.	Unless rad monitor has self checking function, failure will be hard to detect, especially low reading failure.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
12. Boronometer Erroneously Indicates High RCS Boron Concentration	1. Mechanical failure 2. High temperature damage from failure of signal from TE-224 and letdown cooling or failure of CVC-521 with failure of letdown cooling	Potential for operator to initiate dilution. Dilution would result in slight reactivity increase, but control rods would control undercooling.	Dilution operation would probably be stopped when no decrease in boron concentration registered at boronometer. Boron concentration could be readjusted by calculated boron addition based on grab sample.
13. Boronometer Erroneously Indicates Low RCS Boron Concentration	1. Mechanical failure 2. High temperature damage from failure of signal from TE-224 and letdown cooling or failure of CVC-521 with failure of letdown cooling	Potential for operator to initiate boration, and overborate the RCS. Reactivity decrease, no noticeable overcooling effect expected.	Detect failure by noting no change in boron reading with boron addition. Correct boron concentration based on grab sample and calculations.
14. Tube Rupture in Regenerative Heat Exchanger	1. External event 2. Corrosion 3. Other internal mechanical damage	Charging flow will preferentially flow to lower pressure outlet, i.e., letdown path instead of to the RCS. Amount of flow recycled through CVCS will depend on break size and location. Probably no net change in RCS inventory.	Trip operating charging pump. Isolate letdown. Shutdown plant and repair component.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
15. Tube Rupture in Letdown Heat Exchanger	1. External event 2. Corrosion 3. Other internal mechanical damage (loose parts)	RCS leak or loss into component cooling water (CCW). Reduced letdown flow to VCT and consequent drop in VCT level. Makeup required from demineralized water tank if in AUTO mode, may be cool (ambient). Boric Acid Storage Tank input (maximum 30 gpm in AUTO mode) will be 150°F. If makeup is in manual mode and VCT level drops, makeup will come from the refueling water storage tank (RWT) (45°F or ambient). Net result is potential for slightly cool makeup to RCS as well as loss of letdown cooling. (See Failure 7)	Alert to failure by low flow at FE-202 and decreasing level in VCT. Isolate letdown flow from RCS. This will lower charging flow temperature more since flow will be stopped through the regenerative heat exchanger, but the leak must be isolated. Monitor TE-229 and isolate charging flow if temperature is too low.
<u>Purification</u>			
16. Ion Exchanger Bypass Valve (CVC-520) Fails Open to Ion Exchangers	1. Mechanical damage 2. Signal from TE-224 fails with failure of letdown cooling	No effect unless letdown cooling has failed. If cooling has failed, resin damage may occur in ion exchanger(s), with eventual plugging and loss of letdown flow. Potential for low temperature charging flow as discussed above due	Alert to failure by PDIS-203, (P across ion exchangers), low flow at FE-202, and high temperature at TE-223. Isolate letdown and charging flow. Shut plant down as required.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		to makeup requirements from demineralized water storage tank (DWST) and loss of flow through regenerative HX.	
17. Ion Exchanger Bypass Valve (CVC-520) Fails Closed to Ion Exchangers	1. Mechanical damage 2. Loss of instrument air	Loss of normal letdown path through ion exchangers. No major short-term effect on RCS.	Shutdown plant and repair when RCS chemistry becomes unacceptable. Monitor RCS chemistry closely.
18. Ion Exchanger(s) Plug(s) or Strainer Plugs	1. Heat damage 2. Loose parts 3. Bad resin supply	Initial loss or reduction of letdown flow. PDIS-204 alarms at 20 psid. VCT level will decrease and initiate makeup water from RWT or DWST, which could result in cooler charging flow to RCS. Net gain in RCS inventory of 44 gpm from the operating charging pump.	Letdown flow can be switched at CVC-520-CV to bypass ion exchangers. Monitor RC chemistry and shutdown plant as required.
19. Ion Exchanger Setup Error: Wrong Resin Loaded, Wrong Exchanger Placed in Operation, or No Resin Loaded	1. Operator error 2. Resin supplier error 3. Laboratory error on new resin sampling	Possible long-term chem-effects. Potential for too much deboration, if not detected by borono-meter, leads to increased RCS activity and potential narrower shutdown margins.	Monitor RCS chemistry and activity to detect failure. Bypass ion exchangers with CVC-520-CV and correct ion exchange setup.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
20. Resin Bed Support Structure in Ion Exchanger Fails or Leaks	1. Corrosion (RCS chemistry) 2. Maintenance error causing mechanical failure	1. Strainer downstream of exchangers plugs, PDIS-204 and PDIS-203 alarm at 20 psid. Loss of letdown flow, VCT level will decrease and initiate automatic makeup from DWST or RWT, which could result in cooler charging flow to RCS. Net gain in RCS inventory from operating charging pump.	Letdown flow can be switched at CVC-520-CV to bypass ion exchangers and resume letdown flow to VCT.
		2. Resin beads leak through strainer if strainer basket is faulty or has not been replaced after maintenance. Resin accumulates slowly in various locations downstream of the VCT out let, resulting in plugging of valves and/or charging pumps. Potential loss of charging flow. Decrease in pressurizer level will run back letdown to minimum setting (29 gpm). Net decrease in RCS inventory at 29 gpm with RC sent to Waste Processing	Alert to failure by no (or low) charging flow on FE-212, high level alarm in VCT and RC inventory accumulating in Waste Processing System. Isolate letdown. Shutdown plant and remove resin.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		System on high level (LC-227A) in the VCT.	
<u>Volume Control Tank (VCT)</u>			
21. VCT Inlet Valve (CVC-500-CV) Fails to Divert Flow from VCT on Demand	1. Control system failure (VCT LC-227A fails) 2. Loss of instrument air (valve fails open to VCT) 3. Mechanical failure	Volume control will typically be out of balance (i.e., some other failure causing high VCT level) in order for this to be demanded. Failure on demand results in overfill of VCT, which may alert the operator to open CVC-513-CV to relieve tank pressure. The VCT inlet spray nozzle may flood, which will stop mixture of RC with hydrogen. Net result is failure to provide hydrogen to the RCS.	Attempt manual switching of the valve. Also, letdown can be isolated and the VCT can be manually drained to the waste processing system.
22. VCT Valve to Waste Gas System (CVC-513-CV) Fails Open	1. Operator error 2. Mechanical wear (valve normally fails closed)	VCT depressurizers causing more hydrogen addition, venting of hydrogen to the waste gas system and potential depletion of the hydrogen supply; after which full VCT depressurization could occur. Hydrogen addition to the RCS would be degraded. Potential for hydrogen ex-	VCT low pressure alarms (PIA-225) at 4 psig. Manually isolate hydrogen supply and CVC-513-CV. Check chemistry. Shutdown plant if required. Assess explosion potential in Waste Gas System.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		plosion accident in Waste Gas System.	
23. Hydrogen Relief Valve CVC-105-RV Fails Open	1. Operator error 2. Mechanical wear (valve normally fails closed)	Hydrogen supply depletes, venting to plant vent. Hydrogen explosion potential in plant vent. Loss of hydrogen addition capability in VCT.	Isolate hydrogen supply. Shutdown and repair component.
24. VCT Outlet Valve (CVC-501-MOV) Fails Closed	1. Inadvertant signal from makeup controller or SIAS 2. Obstruction (plugged valve)	VCT level will rise, resulting in letdown flow getting diverted to the waste processing system. If CVC-504-MOV from RWT opens, as it normally does with closure of CVC-501-MOV, the only effect is potentially cooler makeup to RCS. But since this valve does not open automatically on high VCT level, charging flow to the RCS may be lost, causing pressurizer level to drop. Letdown will run back to its minimum setpoint of 29 gpm, but will not isolate automatically. Net RCS loss of 29 gpm.	Isolate letdown and manually operate makeup valve CVC-504-MOV as required.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
25. VCT Outlet Valve (CVC-501-MOV) Fails Open When Demanded to Close (Low Level in VCT)	1. Control signal failure 2. Mechanical failure (valve stuck open) 3. Power supply failure	As a single failure, no significant effect on charging pumps and flows as long as charging flow is supplied by CVC-504-CV from the RWT. (See Item 55 for SIAS effect.)	Manually open makeup flow valve or isolate letdown.
26. Seal Return Relief Valve (CVC-RV-199) Fails Open	1. Internal or mechanical failure 2. Maintenance error in valve setting	Loss of reactor coolant to the reactor coolant drain tank through the 1" relief valve line instead of returning to the VCT.	Isolate RC loss with valve CVC-507-CV.
<u>Charging Pumps</u>			
27. Charging Pumps Fail	1. Common cause mechanical failure (broken diaphram, inlet check valve failed, etc.) 2. Loss of seal and plunger flush water from overhead supply tank 3. Blockage due to loose parts, debris or resin beads in system 4. Loss of power on buses 480 V 11A, 11B, 14A, and 14B	Loss of charging flow to RCS. If only one pump has failed, pressurizer level will drop and initiate the second and/or third pump to resume charging flow. If charging pumps are unavailable, pressurizer level will drop and initiate runback of letdown (minimum setpoint of 29 gpm). Net RCS loss of 29 gpm.	Isolate letdown. Shutdown plant if pressurizer level has dropped too low.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
28. Charging Pump Suction or Discharge Relief Valve(s) Fail Open (RV-315, RV-318, RV-321, RV-324, RV-325, and/or RV-326)	1. Internal or mechanical failure 2. Maintenance error in valve setting	Part of flow relieves to waste processing system (about 20%). Failure of discharge relief will likely open suction relief. Degraded charging pump discharge flow. Probably will not significantly impact CVCS system operability, although a loss of reactor coolant to the waste processing system through the failed relief valve, will occur.	Isolate faulty relief valves with manual pump suction isolation valves (CVC-164, CVC-170, and/or CVC-176). Isolate letdown flow if no charging pump is operable.
29. Charging Line to Regenerative Heat Exchanger and RCS Plugs (HX Inlet Valve, HX Tubes, or FE-212 Plugs)	1. Loose parts, boron buildup, or debris in line 2. Operator error related to valve closure	Loss or reduction of charging flow to RCS. Blockage may cause high pressure at charging pump discharge, subsequent opening of the charging pump discharge relief valves. Pressurizer level will drop and initiate runback of letdown (minimum setpoint of 29 gpm). Net RCS loss of 29 gpm.	Isolate letdown. Shutdown plant if pressurizer level has dropped too low to operate.
30. Charging Pumps Fail to Trip on Demand	1. Loss of control power on 125 VDC panels 11 and 21 2. Control signal failure	Excess charging flow delivered to the RCS. Pressurizer level and pressure may rise. Maximum net increase	Charging flow to the RCS can be isolated by the operator with valves CVC-518-CV and CVC-519-CV or the breaker can be manu-

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		in RCS inventory of 104 gpm and minimum of 4 gpm.	ally tripped at tbe breaker front.
Demineralized Water Makeup			
31. Reactor Coolant Makeup (RCMU) Pumps Fail on Demand	1. Mechanical failure 2. Maintenance failure 3. Makeup control signal fails (AUTO mode only) 4. Loss of power (MCC-105R and MCC-115R)	Loss of demineralized water to the RCS on demand. This would fail operations in the DILUTE mode. In the AUTO mode, if failure was undetected, excess boron addition to the RCS could occur (makeup from the boric acid pumps would be undiluted). Failure would probably be detected in the MANUAL mode. Also any metered chemical addition would cease, causing RCS pH to gradually decrease.	Provide makeup from the RWT and isolate normal VCT automatic makeup.
32. Filter Downstream of RCMU Pumps Plugs, and PDIS-2530 Fails	1. Mechanical failure of instrument 2. Debris in line 3. Maintenance failure	Same as above (loss of demineralized water flow).	Isolate filter and repair, and open filter bypass CVC-317.
33. Water Makeup Flow Element Plugs FE-210X	1. Filter maintenance error 2. Mechanical failure of instrument	Same as above (loss of demineralized water flow).	Provide makeup from RWT and isolate normal VCT makeup for repair.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
34. Water Makeup Control Valve (CVC-210X-CV) Fails Closed	1. Loss of instrument air 2. Control signal failure 3. Mechanical failure or plugging	Same as above (loss of demineralized water flow).	Same as above.
35. Water Makeup Control Valve (CVC-210X-CV) Fails Open	1. Control signal or controller failure 2. Mechanical failure 3. Flow transmitter failure	Dilution occurs in makeup system if makeup is in AUTO mode. Failure would probably be detected in MANUAL mode.	Supply makeup from RWT and repair component. Failure may be hard to detect when in AUTO mode or if transmitter fails.
<u>Boric Acid Batching Tank</u>			
36. Immersion Heaters Fail	1. Power supply failure 2. Mechanical failure 3. Controller fails	Tank discharge valves could plug from boron precipitation and failure to dissolve boric acid, which could prevent boric acid addition to storage tanks. Could jeopardize boric acid supply and ultimately result in RCS dilution or failure of boron addition on SIAS (although unlikely).	Repair heaters. Utilize boric acid from RC waste evaporator if required.
37. Mixer Fails	1. Power supply failure 2. Mechanical failure	Same as above.	Same as above.
38. Low Boron Concentration Makeup	1. Operator error 2. Boric acid supplier error	Low boric acid concentration in boric acid storage tanks (BASTs). Net result is potential boron dilution in	If failure is detected, concentration in BAST can be adjusted via calculated addition of concentrated boric

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		the RCS in the AUTO makeup mode, and underboration when required in the BORATE mode.	acid through the batching tank.
39. High Boron Concentration Makeup	1. Operator error 2. Boric acid supplier error	Excess RCS boration in AUTO, MANUAL, and BORATE makeup modes.	If failure is detected, concentration in BAST can be adjusted via water addition through the batching tank.
Boric Acid Storage Tanks (BASTs) and Pumps			
40. Heat Tracing on BAST Inlet Fails	1. Power supply failure 2. Mechanical failure	Possibly no effect since flow into tank is heated. However, boric acid sitting inline could precipitate and eventually plug line. Boric acid addition to BASTs would be prevented. However, BASTs have large capacity (approximately 9500 gal ea.).	Monitor BAST levels and locally heat inlet lines to restore addition capability.
41. BAST Heaters Fail on Both Tanks	1. Controller failure 2. Power supply failure (MCC-104R and MCC-114R) 3. Mechanical failure	Boric acid precipitates and plugs tank outlet valves if solution is not continuously recirculated (providing mixing). Loss of boric acid addition capability from BAST. In AUTO makeup mode, RCS boron gets diluted. On SIAS no BAST flow is delivered to RCS. In MANUAL mode, failure will probably be detected.	RWT can provide makeup to RCS. Isolate normal AUTO makeup.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
42. Heat Tracing to Pumps and Gravity Valves Fails	1. Power supply failure 2. Mechanical failure	Same as above. (Loss of boric acid addition capability from BAST.)	Same as above.
43. Boric Acid Pumps Fail	1. Makeup controller failure 2. Power supply failure 3. Mechanical failure 4. Loss of cooling water to seals or bearings	Loss of normal boric acid supply for makeup (AUTO and BORATE modes). Boron dilution occurs in RCS if makeup is in AUTO mode. Failure of only one operating boric acid pump could also produce this effect if the failure is not detected and the second pump is not aligned for service.	Isolate normal AUTO makeup. Initiate emergency boration if required with gravity feed valves.
44. Boric Acid Pump Discharge Line Heat Tracing Fails	1. Power supply failure 2. Mechanical failure	Strainer or other line components plug and design flow is lost. Boron dilution occurs in RCS if makeup is in AUTO mode.	Same as above. Also the recirculation path to the BASTs could be realigned to provide flow around the strainer to the VCT, if this line is not blocked from heat tracing failure.
45. Boric Acid Makeup Control Valve (CVC-210Y-CV) Fails Closed	1. Loss of instrument air 2. Control signal or controller failure 3. Mechanical failure or plugging	Loss of boric acid flow to makeup stream. Boron dilution occurs in RCS if makeup is in AUTO mode.	Failure may be hard to detect when in AUTO mode or if transmitter fails. Assess boron requirements. Open and close CVC-238 as required to deliver boric acid to RCS via charging pump suction.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
46. Boric Acid Makeup Control Valve (CVC-210Y-CV) Fails Open	1. Control signal failure 2. Mechanical failure	Excess boric acid delivered to the RCS on AUTO or MANUAL makeup demand. Failure will probably be detected in MANUAL model.	Assess RCS boron concentration. Operate in dilute mode if necessary. Isolate normal makeup and utilize makeup from RWT during repair.
<u>Volume Control Tank (VCT) Makeup</u>			
47. Makeup Control Valve (CVC-512-CV) Fails Closed	1. Loss of instrument air 2. Control signal failure 3. Mechanical failure or plugging (i.e., heat tracing fails)	Normal makeup (AUTO mode) to VCT is stopped. Relief valve (CVC-376) around control valve may open allowing some makeup to VCT (opens at 70 psig). If VCT reaches low-low level, makeup will automatically be supplied to the charging pump suction header from the RWT (via CVC-504-MOV).	Verify RWT flow path or utilize path from normal makeup supply to CVC-504-CV via manual valve CVC-254.
48. Makeup Control Valve (CVC-512-CV) Fails Open	1. Control signal failure 2. Mechanical failure 3. Solenoid failure	Potentially no effect in all operating modes, since pumps are off when makeup is not demanded. However, if control signal failure is the cause, the pumps will also be on, and overfilling of the VCT can occur. Any letdown will be directed to the waste processing system on high level in the VCT.	Secure RCMU pumps and boric acid pumps if operating. Isolate failed valve.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		Overfilling may prevent mixture of required hydrogen with makeup with eventual result of low hydrogen concentration in the RCS. VCT may overpressurize.	
49. Relief Valve (RV-194) Around Makeup Control Valve Fails Open	1. Maintenance error 2. Mechanical failure	Minimal effect since pumps will be off when control valve is closed. Relief valve dumps back into makeup line and into VCT. Any overfill will occur more slowly since relief line is only 3/4" vs. the 3" diameter makeup line.	Same as above.
50. RWT Makeup Valve (CVC-504-MOV) Fails to Open on Demand (Low Level in VCT)	1. Power supply failure 2. Mechanical failure 3. Control signal failure	Loss of charging flow to RCS due to loss of flow to charging pump suction. Pressurizer level may drop and initiate runback of letdown flow. Potential net RCS loss of 29 gpm (minimum letdown setting).	Isolate letdown if required. Operate makeup in manual mode with makeup stop valve (CVC-512-CV) open to restore VCT level. Water makeup can also be provided to charging pump suction from RCMU pumps through the chemical addition tank (1-1/2" line to tank and 1/2" line out of tank to charging pump suction).

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
51. Manual Valve from RWT to CVC-504-MOV (component above) is Closed on Demand	1. Maintenance or operator error	Same as above, given that makeup from the RWT is demanded.	Same as above.
SIAS Components			
52. BAST Recirculation Control Valves (CVC-518-CV and CVC-511-CV) Fail Closed	1. Loss of instrument air 2. Mechanical failure 3. Inadvertant SIAS signal	No significant effect, although mixing in BASTs is reduced. Relief valves around these recirculating valves to BASTs exist, but will typically not be required since pumps do not operate unless makeup is demanded, upon which main pump discharge line also opens to VCT.	Repair component(s). Failure will be hard to detect.
53. BAST Recirculating Control Valves (CVC-518-CV or CVC-511-CV) Fail to Close on SIAS Demand	1. Maintenance failure 2. Mechanical failure	Potential net reduction in SI boric acid flow but not a significant amount (<25%).	Provide emergency boration with gravity feed valves, as required, based on RCS boron requirements.
54. Boric Acid Gravity Feed Valves (CVC-508-MOV and CVC-509-MOV) Fail to Open on SIAS Demand	1. Power supply failure 2. Mechanical failure 3. Control signal failure	One path for boric acid addition to charging pump suction is lost. Other path from boric acid pumps via CVC-514-MOV remains.	Verify operability of other boric acid path to charging pump suction.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
55. VCT Outlet Valve (CVC-501-MOV) Fails to Close on SIAS Demand	1. Power supply failure 2. Mechanical failure 3. Control signal failure	SIAS boric acid flow directly from BAST is diluted with VCT flow. Extent of dilution depends on system hydraulics (discharge heads, etc.). VCT volume is 3880 gal. Less shutdown margin than desired due to dilution.	Attempt to manually close valve.
56. Spare Charging Pumps Fail to Start on SIAS Demand	1. Power supply failure (4 KV Bus 11 or 4 KV Bus 14) 2. Mechanical failure 3. Control signal failure	Potentially only 1/3 capacity SIAS boric acid flow delivered to the RCS on demand. Reduced shutdown margins achieved.	Manually start charging pumps on detection of failure, if pumps are not failed mechanically.
57. Seal Return Valves to VCT Fail to Close on SIAS Demand	1. Mechanical failure 2. Control signal failure	No significant effects on SI capability. VCT may fill from seal return since SIAS will close the VCT outlet valve, but the fill rate will be slow.	Attempt to manually close the valves. Open the VCT outlet valve if the VCT has filled to too high a level.
58. SIAS Fails to all CVCS Components	1. Control signal failure 2. Control power failure (although control power default may produce an SIAS)	Automatic delivery of concentrated boric acid from CVCS (132 gpm design flow) is failed.	Initiate emergency boration alignment on detection of failure. Flow from CVCS is probably not required on SIAS, but provides a safety margin.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Chemical Makeup			
59. Metering Pump Fails	1. Power supply failure 2. Mechanical failure 3. AUTO control signal failure 4. Loss of pump cooling water	Loss of normal continuous chemical addition. Failure will be hard to detect. Gradual decrease in RCS pH.	Pump can be operated locally if AUTO control has failed. RCS chemistry can be corrected by flushing chemicals into the charging pump suction via the chemical addition tank and RCMU pump(s).
60. Metering Pump Fails to Stop in AUTO Mode	1. Control signal failure 2. Loss of control power	Excess hydroxide delivered to RCS. Gradual increase in RCS pH. Failure may be hard to detect.	Adjust RCS chemistry with addition of water and boric acid and letdown reactor coolant to waste processing system.
61. Chemical Addition Discharge Block Valve(s) (CVC-264, CVC-296, CVC-338, CVC-348, CVC-471, CVC-478) are Closed	1. Operator or maintenance error 2. Valves stuck closed	Two paths are available, with one normally open. Metering pump suction valve can fail both paths. One valve on each path can fail chemical addition. Failure will be hard to detect. Metering pump discharge may overpressurize, contributing to pipe break. Loss of normal chemical addition can lead to gradual decrease in RCS pH.	Same as for metering pump failure (correct chemistry with flushing through the chemical addition tank) if valve to charging pump suction (CVC-338) is not stuck closed.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
62. Makeup Error in Chemical Addition Metering Tank (Hydroxide Concentration Too High or Too Low)	1. Operator error 2. Chemical supplier error	Wrong chemical concentration in RCS (pH too high or too low). Long term effect.	Failure may be hard to detect unless RCS grab sample is normal procedure. RCS composition can be adjusted quickly with flush from chemical addition tank.
63. No Chemicals in Chemical Addition Metering Tank	1. Operator error 2. Tank drain valve open	Loss of normal (slow) chemical addition. Failure will be hard to detect. Gradual decrease in RCS pH.	Restore tank integrity. Utilize flush tank as required.
64. Chemical Addition (Flush) Tank Discharge Strainer Failed	1. Internal failure 2. Maintenance failure (strainer reversed or not replaced)	Potential debris in system may fail charging pumps and charging flow. See other "loss of charging flow" effects.	Isolate strainer and/or chemical addition. Isolate letdown flow if charging flow has failed.
<u>Pressurizer Level Regulating System Interfaces</u>			
65. Loss of Non-Vital Power to Regulating System Relays (AC bus 1Y10) or Loss of Vital Power to Regulating System Bistables (bus 1Y10 or 1Y02)	1. Loss of power to bus 2. Fault on bus	Letdown control valve closes, backup charging pump start and all pressurizer heaters de-energize. Pressurizer high level transient with potential for high pressure transient from operating charging pumps on low pressure transient if loss of heaters is controlling.	Assume manual control of letdown valve and charging pump operation. If power on 1Y01 or 1Y02 failed utilize the unfailed power supply to resume pressurizer level control. Pressurizer heaters can also be turned on manually.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
66. Pressurizer Level Transmitter Fails High (LT110X or LT110Y)	1. Power surge fails power supply regulator 2. Capacitance bridge circuit fails or other internal components fail	Letdown control valve opens, while any operating backup charging pumps trip. VCT fills. Level in pressurizer drops. Pressurizer backup heaters energize on initial high level signal and on subsequent low pressurizer pressure accompanied by the inventory loss. Heaters would not de-energize on actual low level in pressurizer as designed due to the transmitter failure. Net loss in RCS inventory of 84 gpm. With incorrect operator response (opening other letdown control valve and tripping last charging pump) net letdown flow (RCS loss) could be as high as 230 gpm.	Assume manual control of CVCS components. Failure may be hard to detect, low pressure transient may be only indication. Switch to alternate regulating system (i.e., system X if Y transmitter is failed).
67. Pressurizer Level Transmitter Fails Low (LT110X or LT110Y)	1. Loss of power to transmitter (Bus 1Y01 or 1Y02) 2. Internal transmitter components fail	High level transient in pressurizer. Letdown control valve runs back, backup charging pumps start, and pressurizer heaters de-energize. Potential high pressure transient in pressurizer with potential to open PORV's.	Switch to alternate regulating system (i.e., system X if Y transmitter is failed). Assume manual control of CVCS components (trip pump and isolate letdown as required).

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
68. Pressurizer Level Setpoint (from Reactor Regulating System) Fails High	1. Signal fault 2. Setpoint device fault	Pressurizer overfill. Correct pressurizer level will appear low and extra charging pumps and runback of letdown flow will be initiated, resulting in overfill of the pressurizer. High pressurizer level will appear normal and correct control response (energize heaters, stop backup charging pumps and increase letdown) will not occur.	Switch to alternate regulating system (X or Y) on detection of failure. Adjust RCS inventory with CVCS.
69. Pressurizer Level Setpoint (from RRS) Fails Low	1. Signal fault 2. Setpoint device fault	Correct pressurizer level will appear too high, causing any extra charging pumps to trip and the letdown control valve to run open; actual level in pressurizer will then be too low, but heaters will still be operating based on decreasing pressure transient and erroneous high level indication in pressurizer.	Switch to alternate regulating system (X or Y) on detection of failure. Adjust RCS inventory with CVCS.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Letdown Temperature Control			
70. Temperature Transmitter (TT-224) on Letdown Heat Exchanger Discharge Fails Low	1. Loss of power supply to transmitter 2. Internal transmitter components fail	If high letdown temperature exists (letdown HX failure, etc.) automatic bypass of radiation monitor, boronometer, and ion exchangers will not be initiated. Potential damage may occur to this equipment. Failure of the boronometer may be a significant effect from this transient.	TI-223 provides a backup for correct temperature indication. Assume manual control of valves to bypass required equipment.
71. Temperature Controller (TIC-224) Output Fails Low (assume signal output is proportional to power supply)	1. Loss of power to to controller 2. Output wire is failed (corrosion or broken during maintenance)	Same as above.	Same as above.
72. Temperature Transmitter (TT-224) or Controller (TIC-224) Fails High	1. Power surge fails power supply regulator 2. Internal components fail	Radiation monitor, boronometer, and ion exchangers in letdown system are bypassed. Loss of continuous purification and monitoring of RC activity and boron concentration.	Assume manual control of bypass valves based on TI-223.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Volume Control Tank Level Control			
73. VCT Level Transmitter (LT-226) Fails Low (LT-226 provides input to LC-227A, LC-227B and LC-226)	1. Loss of power to transmitter 2. Internal components fail	Failure causes controller LC-227A and B to initiate makeup from the RWT (via CVC-504-MOV) and to close the VCT outlet valve. Failure also causes controller LC-226 to initiate makeup to the VCT and fail to shut off makeup when required. The VCT would overfill. Diversion of letdown to the waste processing system on high VCT level (from LC-227) would also be failed, contributing to the overfill.	Assume manual control of appropriate valves to stop overfill. Failure may be hard to detect since all VCT level indication is based on this transmitter.
74. VCT Level Transmitter (LT-226) Fails High	1. Power surge fails power supply regulator 2. Internal components fail	Failure causes controller LC-227 to divert letdown flow from VCT to the waste processing system and causes LC-226 to fail to provide needed automatic makeup to the VCT as the VCT level drops. The failure also causes controller LC-227 to fail to initiate makeup from the RWT, when VCT level is actually low, resulting in loss of flow to the charging pumps and loss of charging	Manually initiate makeup from the RWT and then realign VCT letdown inlet valve to the VCT. Failure may be hard to detect since low level indicatiton and alarm will be failed.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		flow to the RCS. The VCT could empty on the order of a half hour from the transmitter failure.	
75. Level Controller LC-227A) Output Fails Low (assume signal output is proportional to power supply)	1. Loss of power to controller 2. Output wire is failed (corrosion or broken during maintenance) 3. Other internal failure	Automatic diversion of letdown from VCT to waste processing system on high level in VCT would be failed. Potential for VCT overfill. Charging flow would not be affected.	Assume manual control of the valve CV-500 as required to avoid overfill.
76. Inadvertent Output From Level Controller (LC-227A)	1. Power surge 2. Other internal failure	Inadvertent diversion of letdown to the waste processing system. Other makeup, either from VCT makeup or RWT, will be provided for charging flow. Flow delivered to the RCS may be cooler than design temperature.	Assume manual control of this valve based on VCT level.
77. Level Controller (LC-227B) Output Fails Low (assume signal output is proportional to power supply)	1. Loss of power to controller 2. Output wire is failed (corrosion or broken during maintenance) 3. Other internal failure	On low-low level in VCT, makeup from the RWT is failed resulting in loss of charging flow to the RCS.	Assume manual control of this valve based on VCT level.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
78. Inadvertent Output From Level Controller (LC-227B)	1. Power surge 2. Other internal failure	No significant effect. Opens RWT makeup valve. More flow available to charging pump section.	Repair component.
VCT Makeup Control			
79. Makeup Level Controller (LIC-226) Output Fails Low	1. Loss of power to controller 2. Output wire is failed (corrosion or broken during maintenance) 3. Other internal failure	No effect unless makeup controller is in AUTO, which it normally is. If in AUTO, VCT makeup fails on demand. Backup makeup from RWT is still operable.	Operate VCT makeup in manual mode and verify operability of backup makeup from RWT.
80. Makeup Level Controller (LIC-226) Output Fails High	1. Power surge 2. Other internal failure	If makeup control is in AUTO, makeup to VCT is initiated and not stopped when required. VCT may overfill. VCT level alarm will not be affected by failure and will annunciate on high level in tank.	Assume manual control of makeup and repair component.
81. Loss of Power to Makeup Flow Control Unit	1. Loss of power to panel 2. Fault at panel	Assuming panel requires power to actuate equipment, makeup valves fail closed and pumps stop. No makeup is delivered to the VCT. Automatic makeup from the RWT will still be available on low level in the VCT.	Restore power to panel. Utilize makeup from the RWT and emergency boration path as required.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
82. Water Makeup Flow Controller (FRC-210X) Fails	1. Maintenance error 2. Flow transmitter (FT-210X) failure 3. Other internal failure	1. Runs water supply control valve open when it should be running it back. Overfeed of water in makeup. Potential long term boron dilution in RCS.	When makeup mode is in AUTO, or flow transmitter has failed, failure will be hard to detect. Repair component.
		2. Runs water supply control valve back when it should be running it open. Underfeed of water in makeup and potential for long term overboration of RCS.	Same as above.
83. Boric Acid Makeup Flow Controller (FRC-210Y) Fails	1. Maintenance error 2. Flow transmitter (FT-210X) failure 3. Other internal failure	1. Runs boric acid supply valve open when it should be running it back. Overfeed of boric acid in makeup and potential for overboration of the RCS.	When makeup mode is in AUTO, or flow transmitter has failed, failure will be hard to detect. Repair component.
		2. Runs boric acid supply valve back when it should be running it open. Underfeed of boric acid in makeup and potential for underboration of the RCS.	Same as above.

Table C2. (continued)

Failure	Possible Causes	Effects	Remedial Actions
84. Makeup Mode Selector Failure	1. Printed circuit board failure	1. Dilution instead of boration may occur and vice versa (unless timer must be set to get flow, i.e., if boric acid line timer was not set, no flow could be discharged).	Isolate VCT makeup. Assess problem and RCS boration. Correct as required, then repair failed components.
		2. Manual mode instead of AUTO would result in loss of automatic makeup to the VCT. Makeup from the RWT would still be available.	Operate with RWT makeup and repair component.
		3. Dilute or borate modes instead of manual (i.e., makeup pumps and boric acid pumps would not operate at the same time). Results in potential RCS over- or under-boration.	Isolate VCT makeup. Assess problem and RCS boration. Correct as required, then repair failed components.

Table C3. Pressurizer level regulating system FMEA

Failure	Possible Causes	Effects	Remedial Actions
1. Loss of Non-Vital Power to Regulating System Relays (AC bus 1Y10)	1. Loss of power to bus 2. Fault on bus	Letdown control valve closes, backup charging pumps start and all pressurizer heaters de-energize. Pressurizer high level transient with potential for high pressure transient from operating charging pumps or low pressure transient if loss of heaters is controlling.	Assume manual control of letdown valve and charging pump operation. If power on 1Y01 or 1Y02 failed utilize the unfailed power supply to resume pressurizer level control. Backup for 1Y01 and 1Y02 is also available on bus 1Y11. Trip charging pumps as required. Turn on pressurizer heaters manually as required. Manual control of letdown valve is lost. If bus is not faulted manually align backup bus 1Y09.
2. Loss of Vital Power to Regulating System Bistables (bus 1Y01 or 1Y02)	1. Loss of power to bus 2. Fault on bus	Same as above.	Assume manual control of letdown valve and charging pump operation. If power on 1Y01 or 1Y02 failed utilize the unfailed power supply to resume pressurizer level control. Backup for 1Y01 and 1Y02 is also available on bus 1Y11. Trip charging pumps as required. Turn on pressurizer heaters manually as required. Manual control of letdown valve is lost. If bus is not faulted manually align backup bus 1Y09.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
3. Pressurizer Level Transmitter Fails High (LT110X or LT110Y)	1. Power surge fails power supply regulator 2. Capacitance bridge circuit fails or other internal components fail	Letdown control valve opens, while any operating backup charging pumps trip. Level in pressurizer drops. Pressurizer backup heaters energize on initial high level signal. Heaters would not de-energize on actual low level in pressurizer as designed due to the transmitter failure. Potential heat damage to pressurizer. Net loss in RCS inventory of 84 gpm. With incorrect operator response (opening other letdown control valve and tripping last charging pump) net letdown flow (RCS loss) could be as high as 256 gpm.	Assume manual control of CVCS components. Failure may be hard to detect, volume control tank high level may be only indication. Switch to alternate regulating system (i.e., system X if Y transmitter is failed).
4. Pressurizer Level Transmitter Fails Low (LT110X or LT110Y)	1. Loss of power to transmitter 2. Internal transmitter components fail	High level transient in pressurizer. Letdown control valve closes, backup charging pumps start, and heaters de-energize. Potential high pressure transient from operating charging pumps or low pressure transient if loss of heaters is controlling.	Switch to alternate regulating system (i.e., system X if Y transmitter is failed). Assume manual control of CVCS components (trip pump and isolate letdown as required).

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
5. Pressurizer Level Setpoint (from reactor regulating system) Fails High	1. Signal fault 2. Setpoint device fault	Pressurizer overfill. Correct pressurizer level will appear low and extra charging pumps and runback of letdown flow will be initiated, resulting in overfill of the pressurizer. High pressurizer level will appear normal and correct control response (energize heaters, stop charging pumps and increase letdown) will not occur.	Switch to alternate regulating system (X or Y) on detection of failure. Adjust RCS inventory with CVCS.
6. Pressurizer Level Setpoint (from RRS) Fails Low	1. Signal fault 2. Setpoint device fault	Correct pressurizer level will appear too high, causing any extra charging pumps to trip and the letdown control valve to run open; actual level in pressurizer will then be too low. Heaters will be energized based on erroneous high level indication in pressurizer, but will still de-energize if lo-lo level setpoint is reached, since lo-lo setpoint is independent of operating level setpoint. On a reactor trip, pressurizer could empty.	Switch to alternate regulating system (X or Y) on detection of failure. Adjust RCS inventory with CVCS.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		Potential pressurizer damage if heaters fail on.	
7. Pressurizer Level Hi Bistable (LC-110XH or LC-110YH) Contacts Fail Open (assumed normally energized closed)	1. Loss of power to module resulting in failure to de-energized position 2. Burnout or wearout of power related components (contacts, etc.)	Heaters are inadvertently energized and all but one charging pump is stopped. On low level LA-110XL or YL would start pumps again. High pressure transient would be initiated but terminated by pressurizer spray (by pressure regulating system).	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.
8. Pressurizer Level Hi Bistable (LC-110XH or LC-110YH) Contacts Fail Closed (assumed normally energized closed)	1. Contact short or arcing caused by corrosion, aging, moisture, swell, etc.	Heaters would fail to energize on high level and if backup charging pumps were operating they would fail to trip automatically. Letdown control valve would still open on demand. Net RCS gain of only 4 gpm. Pressure regulating system would not turn on heaters (no low pressure developing). Slow pressurizer overfill transient. High level alarm would still be operable.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
9. Lo-Lo Bistable (LC-110XL or LC-110YL) Contacts Fail Open (assumed normally energized closed)	1. Loss of power resulting in failure to de-energized position 2. Burnout or wearout of power related components	Even if level was not low, or if pressure was low, pressurizer heaters would de-energize, resulting in slow pressure decrease in the pressurizer.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.
10. Lo-Lo Bistable (LC-110XL or LC-110YL) Contacts Fail Closed (assumed normally energized closed)	1. Contact short or arcing caused by corrosion, aging, moisture, swell, etc.	On low low level, heaters will not de-energize. Charging pumps will still energize and letdown control valve will close on demand. Potential pressurizer damage from dry heater operation if low low level exists. Lo-lo level alarm may also be failed, but low level alarm will be operable.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable. Switch manual heater control from "AUTO" to "OFF".
11. Lo Bistable (LA-110XL or LA-110YL) Contacts Fail Open (assumed normally energized closed)	1. Loss of power resulting in failure to de-energized position 2. Burnout or wearout of power related components	All charging pumps energize and, on low level, low level alarm fails. Lo-lo level alarm will still function on demand. Automatic response of letdown control valve is not affected. Net RCS gain of 4 gpm.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
12. Lo Bistable (LA-110XL or LA-110YL) Contacts Fail Closed (assumed normally energized closed)	1. Contact short or arcing caused by corrosion, aging, moisture, swelling, etc.	Low pressurizer level alarm will actuate inadvertently. May induce operator to raise level, initiating an increasing level transient. High level alarm is not affected by failure and should actuate if level gets high enough.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.
13. Hi Bistable (LA-110XH or LA-110YH) Contacts Fail Open (assumed normally energized open)	1. Contact short or arcing caused by corrosion, aging, moisture, swelling, etc.	On high pressurizer level, high level alarm fails. May degrade operator response in the event of high level. Automatic response of letdown control valves and charging pumps is not affected.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.
14. Hi Bistable (LA-110XH or LA-110YH) Contacts Fail Closed (assumed normally energized open)	1. Loss of power to module resulting in failure to nonpower position 2. Burnout or wearout of power related components (contacts, etc.)	High pressurizer level alarm will actuate inadvertently. May induce operator to lower level, initiating a decreasing level transient. Low level alarm is not affected by failure and should annunciate if level gets low enough.	Switch to alternate (X or Y) regulating system to utilize redundant operable bistable.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
15. LIC-110X (or LIC-110Y) Controller Fails Low (low output)	1. Loss of power to controller 2. Output wire is failed (corrosion or broken during maintenance) 3. Other internal failure	Backup charging pumps start and letdown control valve closes. Increasing level transient initiated. At high level alarm setpoint, alarm will still annunciate and LC-110H will de-energize backup charging pumps. Net RCS gain of 15 gpm (44-29) after backup charging pumps trip.	Switch to alternate (X or Y) regulating system to utilize redundant operable controller. Trip last charging pump if level rise is not controlled.
16. LIC-110X (or LIC-110Y) Controller Fails High (high output)	1. Power surge 2. Other internal failure	Backup charging pumps trip and letdown control valve opens. Decreasing level transient initiated. But, at low level alarm setpoint, low level alarm will annunciate and backup charging pumps will start automatically. Level will maintain around low level setpoint with pumps starting and stopping.	Switch to alternate (X or Y) regulating system to utilize operable controller.
17. Charging Pump Bistables LC-110-1 and 110-2 Fail On (contacts closed)	1. Contact short or arcing caused by corrosion, aging, etc.	Backup pumps will fail to energize from controller on demand. Low level alarm bistable will not be affected by failure and will start and stop both pumps around low level setpoint.	Manually operate backup pumps as required.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
18. Charging Pump Bistables LC-110-1 and 110-2 Fail Off (contacts open)	1. Loss of power 2. Burnout or wearout of power related components	Backup pumps will start inadvertently. High level alarm will not be affected by failure. When level reaches setpoint of LC-110XH or YH bistable, pumps will deenergize.	Manually trip pumps as required to maintain level.
19. Relays (LC-110H) Fail to Close on Demand (when deenergized and when hi level exists)	1. Burnout or wearout of power related components	On high level, heaters are not energized and charging pumps are not stopped, but letdown control valve will still open. Net minimum RCS gain of 4 gpm.	Manually trip pumps as required to maintain level.
20. Relays (LC-110H) Fail Closed (normally energized open)	1. Loss of power 2. Contact short or arcing caused by corrosion, moisture, aging, etc.	No significant overall effect. Pressurized heaters are inadvertently energized and backup charging pumps will stop. Heaters will deenergize if lo lo level exists. Also spray can offset any pressure effect. Backup charging pumps will not be started automatically on demand, but letdown control valve can still respond to any low level transient.	Manually control charging pumps.

Table C3. (continued)

Failure	Possible Causes	Effects	Remedial Actions
21. Relays (LC-110L) Fail to Open On Demand (when de-energized and when lo lo level exists)	1. Contact short or arcing caused by corrosion, moisture, aging, etc.	Heaters will not automatically de-energize on lo lo level. Potential pressurizer damage.	Manually switch heaters off on lo lo level alarm.
22. Relays (LC-110L) Fail Open (normally energized closed)	1. Loss of power 2. Burnout or wearout of power related components	Heaters would fail to energize on demand. Could lead to low pressure transient in RCS, with potential core boiling. Also degraded level control on high level in pressurizer.	Monitor RCS pressure. Manually control heaters as required.
23. Charging Pump Relays Fail to Close (when de-energized and on lo level)	1. Burnout or wearout of power related components	On demand, backup charging pumps will fail to start. Letdown control is not affected and can maintain level.	Manually control pumps as required. Monitor level and letdown control valve performance. Utilize spare relay from pump selection.
24. Charging Pump Relays Fail Closed	1. Loss of power 2. Contact short or arcing caused by corrosion, moisture, aging, etc.	All charging pumps are energized. Letdown control valve will run open in response to resulting high level. Net RCS gain of 4 gpm (132-128).	Charging pumps can be manually tripped and started. Manually operate pumps as required.

Table C4. Reactor coolant pressure regulating system FMEA

Failure	Possible Causes	Effects	Remedial Actions
1. Pressure Transmitter (PT-100Y or PT-100X) Fails Low	1. Loss of power on operating vital bus (1Y01 or 1Y02) 2. Loss of power to transmitter (faulted wires, etc.) 3. Internal transmitter components fail	A zero current demand signal will be produced indicating a low pressure condition. Pressurizer spray valves will close, all pressurizer heaters will energize and a low pressure alarm will annunciate. Actual pressure will increase due to heater operation, which will cause the PORVs to lift. If fault is loss of vital power and pressurizer level regulating system is on same bus, all heaters will de-energize on a false lo-lo level signal. The spray valves will still be closed and a low pressure alarm will still annunciate, but no transient will develop. If a high pressure transient did develop, manual response would be required to open spray valves. If low pressure existed, the heaters could not be energized as required, even manually. A decrease in pressure would occur with an eventual thermal margin/low pressure reactor trip.	Switch to alternate regulating system (X or Y) to utilize operable alternate transmitter. Also utilize manual control of heaters and/or spray, as required.

Table C4. (continued)

Failure	Possible Causes	Effects	Remedial Actions
2. Pressure Transmitter (PT-100Y or PT-100X) Fails High	1. Power supply regulator fails due to power surge 2. Internal transmitter components fail	Spray valves will open fully, all heaters will de-energize, and high pressure alarm will annunciate. Actual pressure will decrease due to 375 gpm spray flow at 548°F. Reactor trip will have occurred by 1750 psia from thermal margin/low pressure trip (assume RT pressure transmitters are separate from regulating system transmitter).	Switch to alternate regulating system (X or Y) to utilize operable alternate transmitter. Isolate spray with manual controller and manually energize heaters as required.
3. Backup Heater Controller (PC-100X or PC-100Y) Fails Low	1. Power surge 2. Failure of bistable relays in closed position (contact short or arcing)	Backup heaters would energize. Pressure would start to increase, but would be controlled by pressurizer spray via controller PIC-100X (or Y).	Switch to alternate regulating system (X or Y) to utilize alternate operable controller.
4. Backup Heater Controller (PC-100X or PC-100Y) Fails High	1. Loss of power resulting in failure to de-energized position (wire failure) 2. Burnout or wearout of power related components (contacts, etc.)	Backup heaters fail to energize on low pressure demand. If pressure drops low enough, thermal margin/low pressure reactor trip will occur.	Utilize alternate regulating system (X or Y), or manually energize heaters with 1HS100-4 to maintain pressure.

Table C4. (continued)

Failure	Possible Causes	Effects	Remedial Actions
5. Proportional Controller (P1C-100Y or P1C-100X) Fails Low	1. Loss of power to controller 2. Internal failure	Pressurizer spray valves close and proportional heaters energize. Pressure would slowly increase in pressurizer, with eventual high pressure alarm. PORVs may lift with high pressure reactor trip. High pressure alarm operability is not affected by failure.	Utilize alternate regulating system (X or Y). Manually turn on spray if required to reduce pressure and avoid reactor trip.
6. Proportional Controller (P1C-100Y or P1C-100X) Fails High	1. Power surge 2. Component short or arcing or other internal component failure	Pressurizer spray valves are opened and proportional heaters are de-energized. Pressure decrease in pressurizer, which cannot be offset by backup heaters. Low pressure alarm will annunciate. Eventual thermal margin/low pressure reactor trip. Pressure may continue to drop. At 1600 psia safety injection signal will actuate.	Isolate spray with manual control. Utilize alternate regulating system for continued operation.
7. High Pressure Alarm Bistables (PA-100X or PA-100Y) Fail Closed	1. Contact short or arcing caused by corrosion, aging, moisture, swelling, etc. 2. Power surge	High pressure alarm inadvertently annunciates. This may induce the operator to reduce pressure manually by opening spray valves and de-energizing heaters. If pressure drops	Verify alarm condition with operable bistables on alternate regulating system (X or Y) before taking manual action.

Table C4. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		low enough, thermal margin/ low pressure reactor trip will occur. Operator would probably stop pressure reduction at this point. Also, low pressure alarm may not be affected by the failure and may annunciate.	
8. Low Pressure Alarm Bistables (PA-100X or PA-100Y) Fail Closed	1. Contact short or arcing caused by corrosion, aging, moisture, swelling, etc. 2. Loss of power resulting in failure to de-energized position	Low pressure alarm inadvertently annunciates. This may induce the operator to increase pressure manually by stopping any pressurizer spray and turning on heaters. High pressure alarm may not be affected by the failure and may annunciate.	Verify alarm condition with operable bistables on alternate regulating system (X or Y) before taking manual action.
9. Pressure Alarm Bistables (PA-100X or PA-100Y) Fail to Initiate Alarms	1. Wearout or burnout of power related components	High or low alarm conditions are not annunciated so that operator backup to automatic response to alarm conditions is not available.	Failure may be hard to detect. On detection, utilize alternate system.
10. Spray Valve Controller (1Y09) Fails Low	1. Loss of power on bus 1Y09 or to component 2. Internal failure	Pressurizer spray fails to actuate on demand. No other effect unless system pressure is out of balance	Utilize hand controller as required to actuate spray flow and reduce pressure.

Table C4. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		(high). Then PORV may lift and high pressure reactor trip may occur.	
11. Spray Valve Controller (1Y09) Fails High	1. Power surge 2. Component short or arcing or other internal component fault	Pressurizer spray fails on (375 gpm max). Pressure decrease in pressurizer which cannot be offset by heaters. Low pressure alarm will annunciate. Eventual thermal margin/ low pressure reactor trip will occur. Pressure may continue to drop. At 1600 psia safety injection signal will actuate.	Isolate spray with manual control.
12. Loss of Vital Power on Operating Bus (1Y01 or 1Y02)	1. Loss of power to bus 2. Fault on bus	Loss of vital power will fail the pressure transmitter low. If the pressurizer Level Regulating System is still powered (i.e., on the alternate bus) all heaters will be energized and the pressurizer spray valves will close; i.e., a high pressure transient will occur; but a low pressure alarm will annunciate. The operating Pressurizer Level Regulating System was on the	Utilize operable power supply on alternate regulating system (X or Y).

Table C4. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		failed bus, the heaters will de-energize on a false lo-lo level signal. The spray valves will still be failed closed and a low pressure alarm will still annunciate. No particular transient will develop from this failure, but existing high pressure transients would require manual response and a low pressure transient could not be controlled since the heaters could not be energized, even manually.	
13. Loss of Non-Vital Power on Bus 1Y09	1. Loss of power to bus 2. Fault on bus	Pressurizer spray valves will close and backup heaters will de-energize. Proportional heaters will also fail off. Low pressure transient will develop. May get low pressure alarm.	Energize backup heaters manually (with handswitch) as required to restore pressure.

Table C5. Reactor regulating system FMEA

Failure	Possible Causes	Effects	Remedial Actions
1. Loss of Instrument Power via 125 V AC Bus Failure	1. Loss of normal power supply to bus 2. Fault on bus	Loss of quick-open to atmospheric dumps and turbine bypass valves. Loss of signal to pressurizer level controller.	1. Switch to alternate supply of buses. 2. Switch to other channel of RRS.
2. I/I Signal Error from RCSI System Fails T_c or T_h High or Low	1. Sensor failure 2. I/I failure	1. Proportional steam dump valve errors in direction of signal error. 2. Pressurizer preprogrammed setpoint for level, errors in direction of signal error.	1. No effect from valve proportional errors, unless turbine trips. 2. Pressurizer level system will change pressurizer level-operator action needed to correct. 3. Switch to unaffected RRS channel.
3. Channel Selector Switch Fails Signal High or Low	Mechanical failure	1. Proportional steam dump valve errors in direction of signal error. 2. Pressurizer preprogrammed setpoint for level, errors in direction of signal error.	1. No effect from valve proportional errors, unless turbine trips. 2. Pressurizer level system will change pressurizer level-operator action needed to correct. 3. Switch to unaffected RRS channel.

Table C5. (continued)

Failure	Possible Causes	Effects	Remedial Actions
4. Network Summing Resistors Fail Signal High or Low	1. Electromechanical failure	1. Proportional steam dump valve errors in direction of signal error. 2. Pressurizer pre-programmed setpoint for level, errors in direction of signal error.	1. No effect from valve proportional errors, unless turbine trips. 2. Pressurizer level system will change pressurizer level-operator action needed to correct. 3. Switch to unaffected RRS channel.
5. Turbine First Stage Pressure Signal Fails High or Low	1. Power loss 2. Transmitter failure 3. I/I failure 4. Resistor failure	1. Proportional steam dump valve errors in direction of signal error. 2. Pressurizer pre-programmed setpoint for level, errors in direction of signal error.	1. No effect from valve proportional errors, unless turbine trips. 2. Pressurizer level system will change pressurizer level-operator action needed to correct. 3. Switch to unaffected RRS channel.
6. Steam Dump Analog Output Component Signal Fails High or Low (excluding quick opening bistable failure high)	1. Failure of electrical components	1. Steam dump proportional control error.	1. No effect on system in normal operation.

Table C5. (continued)

Failure	Possible Causes	Effects	Remedial Actions
7. Level Setpoint Pressurizer Module Firmware Fails High or Low	1. Failure of electrical components	1. Preprogrammed pressurizer level setpoint changes.	1. Operator adjust or shut unit down and repair module.
8. Quick Opening Bistable Fails High or Tav Error (T_{av}-T_{ref}) Fails High	1. Bistable Fails High	Places the turbine bypass valves and the atmospheric steam dump valves in a failed state such that, following turbine trip, the valves would open and RCS overcooling would occur.	--

Table C6. Main feedwater and condensate FMEA

Failure	Possible Causes	Effects	Remedial Actions
<u>Steam Generator Overfill</u>			
1. Feedwater Regulating Valve (FW 1111 or 1121) Fails Open	1. Mechanical Failure of Valve or Operator 2. Controller (FC 1111) Opens Valve 3. Erroneous Controller Inputs	SG level increases initiating turbine and reactor trip. Prior to turbine trip, overfill of the SG may result in carryover of moisture into the main turbine, causing turbine blade erosion and/or failure. Following turbine trip, the regulating valve may be signaled to close and the bypass opened. SG overfill potential exists if the valve remains open. Extensive injection of water into steam lines could jeopardize steam line integrity.	Operator should attempt to throttle the valve manually if possible and, if required, trip the main feedwater pumps manually to prevent SG overfill. Confirm subsequent automatic initiation of auxiliary feedwater. Operator should manually override the controller if it is the problem. Operator also may attempt to isolate or control flow using the motor operated isolation valve.
2. Feedwater Regulating Valve (FW 1111 or 1121) Fails to Close Following Turbine Trip	1. Mechanical Failure of Valve or Operator 2. Loss of Pneumatic Supply While Valve is Open a. Loss of Instrument Air Supply	Following reactor trip, SG level will increase. Unless controlled, the SG overfeed will result in injection of water into the steam lines. Extensive injection could jeopardize steam line integrity.	Operator should attempt to throttle the valve manually and, if required, trip the main feedwater pumps prior to overfilling SG. Confirm the subsequent automatic initiation of auxiliary feedwater.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	b. Isolation of Pneumatic Supply Due to Solenoid Valve Failure or Failure of 120 VAC Buses Y09 or Y10		
	3. Controller (FC 1111, 1121) Fails to Close Valve		
3. Feedwater Regulating Bypass Valve (FW 1105, 1106) Remains Open Following Reactor/Turbine Trip	1. Control Room Operator Fails to Throttle Either Bypass Valve Manually Following Reactor Trip 2. Mechanical Failure of Valve or Operator 3. Controller (LIC 1105, 1106) Fails	Following reactor trip, the main feedwater regulating valves close and the bypass open to maintain 5% flow. As the residual heat generated in the core decreases, the SG level will begin to increase slowly. The control room operator is required to throttle the bypass valves manually to maintain SG level. If the valves are not throttled, SG overfill and possibly damage to the steam lines or their supports could occur.	Operator should throttle bypass valve manually if possible. If required, isolate flow path or trip main feedwater pumps prior to SG overfill.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
4. Main Feedwater Isolation Valves (FW-4516-MOV, FW-4517-MOV) Fails to Close	1. Loss of Electric Power from 4 KV Bus 11 (ZA) and 14 (ZB) 2. Mechanical Failure	Potential for containment overpressurization if failure accompanies SGIS.	Restore power, if possible.
5. Feedwater Pump 11, 12 Fails to Trip	Failure of 125 VDC Bus 11 and 21, Respectively	Potential for Steam Generator Overfill following SGIS or CSAS conditions. Also impacts RCS overcooling.	Restore power, if possible.
<u>Insufficient Flow of Feedwater to SG</u>			
6. Feedwater Regulating Valve Fails Closed (FW-1111-CV, FW-1121-CV)	1. Mechanical Failure Causes Valve to Close 2. Controller (FC 1111) Fails Causing Valve to Close 3. Pneumatic Supply Isolated While Valve is Closed	Steam Generator level decreases resulting in reactor trip. Auxiliary feedwater is designed to actuate upon low SG level. Failure to supply feedwater to the steam generator may result in RCS undercooling.	Operator should manually control valve if possible. Operator should start auxiliary feedwater system if it is not

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	4. Erroneous Inputs to Controller Cause Valve to Close. Inputs Include: a. Steam Flow Rate (FT1011, 1021) b. Feedwater Flow Rate (FT1111, 1121) c. Downcomer Level (LT1111, 1121)	Spurious signals including high feedwater flow rate and high downcomer level might cause the controller to incorrectly adjust the feedwater regulating valve to the closed position.	
7. Header or Valve Ruptures	1. Metal Defects; Stress Corrosion Cracking	Loss of main feedwater flow to steam generator.	
8. Motor Operated Valve Fails Closed (Outside Containment FW-4516-MOV)	1. Mechanical Failure Causes Valve to Close 2. Spurious Signal Causes Valve to Close	Fails flow to steam generator.	Reopen valve if possible, control steam flow from affected steam generator.
9. Mini-Flow Control Valves Fail Open (FW-4484-CV, FW-4484A-CV)	1. Mechanical Failure Causes Valve to Open 2. Valve Controller Fails, Opening Valve	Minimum flow control valve fails open resulting in a reduction of feedwater flow to the steam generator.	Operator manually shuts valve.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
10. Main Feedwater Pump Trip	1. Mechanical Failure Causes Pump to Trip 2. Turbine Control and Lubrication High Pressure Oil System Fails	Steam Generator level decreases resulting in reactor trip. Auxiliary feedwater should be manually started if not automatically actuated.	Operator should verify auxiliary feedwater flow is started. If auxiliary feedwater is not automatically started, operator should manually start system.
	3. Loss of Steam from Reheat Steam System (Above 40% Pump Capacity) 4. Loss of Main Steam (Below 40% Pump Capacity) 5. LP Steam Control Valves Fail Closed 6. Turbine Exhaust Valves Fail Closed 7. Turbine Speed Controller Fails 8. Turbine Overspeed Causes Pump Trip 9. Low Suction Pressure Trips Pump		Admit HP steam from Main Steam System to pump turbine if LP steam flow fails.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	10. High Discharge Pressure Trips Pump		
	11. Low Vacuum Causes Pump Trip		
	12. Turbine Casing High Water Level Causes Pump Trip		
	13. High Thrust Bearing Wear Trips Pump		
<u>RCS Undercooling</u>			
11. Degraded Feedwater Flow to Steam Generator	1. Loss of 13 kV Service Bus 11 Coupled With Loss of Diesel Generator Power	Trips Condensate and Condensate Booster pump resulting in the loss of main feedwater flow. It also trips motor driven auxiliary feedwater pump. Steam driven auxiliary feedwater pump is not impacted.	Restore bus.
12. Degraded Feedwater Flow to Steam Generator-	1. Loss of 4 kV Bus 11 Resulting in Isolation of the 13 kV Service Bus 11 From the 500 kV Bus	Trips Condensate and Condensate Booster pump resulting in the loss of main feedwater flow. It also fails to power motor driven auxiliary feedwater pump. Steam driven auxiliary feedwater pump is not impacted.	Restore bus.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Other Failures			
13. SGFP Seal Water Failure	1. Seal Water Booster Pump Trips 2. Filters Clogged 3. Loss of Electric Power (MCC-101) Bus 11A (ZA) 4. Control Valve Failure (FW-4702-CV, FW-4705-CV) 5. Controller PDC-4702 Spuriously Closes Valve	Failure to supply clean cooling water to the SGFP seals. The time it would take a loss of seal water failure to fail SGFP is unknown.	Upon failure of one of the seal water booster pump trains, operator should verify the standby pump train is started. If it has not started, operator should manually actuate pump train.
14. H.P. Feedwater Heaters Fail to Heat Feedwater	Valve Closes Failing Flow to Feedwater Heater	Results in lower SG feedwater temperature and excessive RCS heat removal. Pressurizer control will mitigate slow pressure and level perturbations.	Manually open steam supply valve, if possible.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Fails to Supply Condensate to SGFP			
1. Condensate Booster Pump 11, 12, 13 Trips	1. Mechanical Failure Trips Pump 2. Low Lube Oil Pressure Trips Pump 3. Low Suction Pressure Trips Pump 4. Loss of Electric Power from 4 KV Bus 12, 12, 13	One pump is required below 50% power; two pumps are required above 50% power; three pumps are operated above 80% power. Failure to supply sufficient net positive suction head for the SGFP will result in cavitation and failure of main feedwater flow.	If pump trips, operator should verify a sufficient number of pumps are operating to provide the necessary flow.
2. Condensate Booster Pump Mini-Flow Valve (1-CD-4486-CV) Fails Open	1. Mechanical Failure 2. Isolation of Pneumatic Supply 3. Controller (1-FIC-4486) Spuriously Opens Valve 4. Spurious Flow Element (1-FE-4484) Signal Causes Controller to Open Valve	Opening the mini-flow control valve will divert part of the booster pump flow back to the hotwell. The mini-flow valve recirculates 1700 gpm to the hotwell with one pump running; and 3400 gpm with two pumps running. Failure of the mini-flow valves in the open position will not affect ability to supply sufficient feedwater for post-reactor trip heat removal.	Operator should verify position of mini-flow control valve during changing conditions. Operator should manually control valve if necessary.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
3. Rupture of Header, LP Heaters 11, 12, 13, 14, 15, Valves, or Drain Coolers	1. Stress Corrosion Cracking; Faulty Manufacturing	Failure of components which could result in a loss of condensate which would fail main feedwater supply.	Isolate ruptured component.
4. Condensate Pump 11, 12, 13 Trips	1. Mechanical Failure Trips Pump 2. Loss of Electric Power from Bus 12, 13, 13 3. Low Suction Pressure 4. Oil Cooling System Failure	One pump is required below 50% power; two pumps are required between 50% power; and three pumps are operated above 80% power. The time it takes for failure of the oil cooling system to fail the pump is unknown. Loss of oil cooling for short periods is unlikely to cause pump trip.	Operator should verify sufficient pump capacity to meet operating power level. Operator should open condensate storage tank makeup valve to provide NPSH.
5. Condensate Booster Pump Fails to Start	1. Mechanical Failure 2. Pressure Switch (PS-4454) Fails to Actuate Standby Pump	Degraded flow to SGFP may result in pump trip.	Operator should attempt manual initiation.
6. Condensate Pump Fails to Start	1. Mechanical Failure 2. Automatic Initiation Fails from PS-4414	Degraded flow to condensate booster pump may result in trip of condensate booster or feedwater pump.	Operator should attempt manual pump initiation.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
7. Condensate Mini-Flow Control Valve (CD-4438-CV) Fails Open	1. Mechanical Failure 2. Isolation Pneumatic Supply 3. Controller (FIC-4438) Spuriously Opens Valve 4. Spurious Flow Element Signal (FE-4438) Causes Controller to Open Valve	Opening the mini-flow control valve will divert part of the condensate pump flow back to the hotwell. Mini-flow valve recirculates 4650 gpm to the hotwell with one pump running and 8800 gpm with two pumps running. Failure of the mini-flow valves in the open position will not affect ability to provide post-reactor trip heat removal.	Operator should verify position of mini-flow control valve during changing conditions. Manually control valve if necessary.
8. Heater Drain Pumps Trip	1. Mechanical Failure 2. Loss of Electric Power from 4 KV Bus 12 or 4 KV Bus 13	Fails to supply a significant flow of LP steam condensate from LP heaters to the condensate header and may result in SGFP trip.	
9. Loss of Condensate from Condensate Storage Tank	1. Tank or Header Rupture 2. Dump Valve (CD-4405-CV) Fails Open 3. Controller (LIC-4405) Spuriously Opens Valve	Unlikely event in which condenser is flooded by stuck open dump valve.	Operator manually closes valve, if possible.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Other System Failures			
10. Fails to Provide Seal Water to:			
a. SGFP Seal Booster Pump	1. Pipe or Valve Rupture 2. Valve Closes	Degraded operation of steam generator feed pump due to loss of seal water.	
b. Condensate Pump	1. Pipe or Valve Rupture 2. Valve Closes 3. Pneumatic Supply Isolated and Valve Closed	Degraded condensate pump operation due to loss of seal water.	Operator could bypass the pneumatic valve by opening the bypass valve.
11. Fails to Provide Makeup Supply to:			
a. Component Cooling Water System	1. Pipe or Valve Rupture	Failure to provide makeup to the Component Cooling System could impact critical components, if a leak in the system remained undetected for an extended period.	Align alternate makeup supply if possible.
b. Service Water System	1. Pipe or Valve Rupture	Failure to supply makeup to Service Water System could impact critical components, if a leak in the system	Align alternate makeup supply if possible.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		remained undetected for an extended period.	
12. Fails to Provide Hotwell Level Control	1. CST Makeup Valve (CD-4406) Fails Closed	Upon low hotwell level this failure could cause trip of the condensate pumps due to low suction head.	Operator may be able to manually open or close these valves. Could also open bypass valve.
	2. CST Makeup Valve (CD-4406) Fails Open 3. CST Dump Valve (CD-4405) Fails Closed	The simultaneous failure of these two valves could cause filling of the condenser, and a loss of condenser as heat sink.	
	4. CST Dump Valve (CD-4405) Fails Open	This failure could result in reduction in the Condensate System inventory due to filling of the Condensate Storage Tank.	
13. Fails to Provide Cooling Water to Steam Seal Exhaust Condenser	1. Pipe, Condenser, or Valve Rupture 2. Valve Closes	This failure will cause the turbine to leak a small quantity of steam and tend to lower condensate temperature.	
14. Fails to Supply Cooling Water to Drain Coolers	1. Valve, Pipe, Cooler Rupture	Failure to provide cooling water to drain coolers would result in the water flashing	Operator should isolate the affected component.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	2. Valve Closes	as it passes through level control valves and piping bends. This leads to increased pipe erosion.	
15. Fails to Supply Cooling Water to Turbine Exhaust Hood Sprays	1. Pipe, Valve Rupture 2. Valve Closes 3. Pneumatic Supply Failure Causes Valve to Close	Minimal impact on plant operation.	
16. Fails to Supply Water to SG Blowdown Recovery Heat Exchanger	1. Valve, Pipe, Heat Exchanger Rupture 2. Valve Closes 3. Pneumatic Supply Isolated Closing Valve	Failure to cool blowdown sufficiently may damage ion exchangers and secondary purification system. Also results in a reduction in thermal efficiency due to decreased heating of condensate.	Bypass valve or component if possible.
17. Fails to Supply Makeup Water to Auxiliary Boiler Deaerator	1. Pipe, Valve, Deaerator Rupture	Failure could lead to failure to remove air from the auxiliary steam system. This results in increased erosion of the system.	
18. Fails to Remove Suspended Impurities from Condensate	1. Bypass Valve (CD-5818-CV) Fails Open	Result in reduced thermal efficiency when impurities plate out on steam generator	Operator may be able to bypass clogged filter.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	2. Pipe, Valve Rupture 3. Filter Clogs 4. Controller (PDIC-5818) Fails	and condenser tubes. May also cause increased erosion of confinement surfaces.	
19. Fails to Remove Ionic Contamination from Condensate	1. Bypass Valve (CD-4439-MOV) Fails Open 2. Pipe, Valve Rupture	Failure of demineralizer system will result in increased corrosion damage to components.	
20. Fails to Provide Chemical Addition from Chemical Addition System	1. Pipe, Valve Rupture	Failure to add ammonia and hydrazine will result in increased corrosion of steel surfaces in contact with water.	
<u>Other Failures</u>			
21. Condensate Booster Pump Mini-Flow Valve (CD-4486-CV) Fails Closed	1. Mechanical Failure of Valve Stem 2. Controller (FIC-4486) Spuriously Closes Valve 3. Spurious Flow Element (FE-4484) Signal Causes Controller to Close Valve	This failure could cause pump trip upon loss of condensate flow through pump. Valve is intended to circulate some flow through pump during low flow conditions.	Operator should manually open valve, if possible. Operator should trip pump to preclude damage, if valve manipulation is not possible.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
22. Condensate Pump Mini-Flow Valve (1-CD-4438-CV) Fails Closed	1. Mechanical Failure 2. Controller (FIC-4438) Spuriously Closes Valve 3. Spurious Flow Element (FE-4438) Signal Causes Controller to Close Valve	This failure could cause pump trip upon loss of condensate flow through pump. Valve is intended to circulate some flow through pump during low flow conditions.	Operator should manually open valve, if possible. Operator should trip pump to preclude damage, if valve manipulation is not possible.
23. Fails to Receive Flow from Heater Drain Pump	1. Valve Closes 2. Pipe Plug	Could fail the flow of feedwater to the steam generator.	Operator should manually open valve, if possible.
24. Fails to Receive Flow from Coolant Waste Evaporator Drains	1. Valve Closes	Failure to discharge to the condensate system may cause failure of the coolant waste processing system.	Operator should manually open valve, if possible. Operator should re-align valves such that flow is diverted to auxiliary boiler deaerator.
25. Loss of Condensate in System	1. Pipe, Valve Rupture 2. Makeup Valve (CD-4406-CV) Fails Closed 3. Condenser Failure 4. Controller (LIC-4405) Spuriously Closes Valve	Unlikely event in which low hotwell level is not replenished by condensate storage tank. Turbine trip will result.	Operator manually opens valve, if possible.

Table C6. (continued)

Failure	Possible Causes	Effects	Remedial Actions
26. Bypass Valves Fail Open Bypassing:			
a. Drain Coolers	1. Mechanical Failure	Drain liquids could flash to steam enhancing erosion. Loss of thermal efficiency.	Attempt to close valve.
b. LP Heaters 11, 12	1. Mechanical Failure	Loss of thermal efficiency. Potential for thermal shock of steam generator.	Attempt to close valve.
c. LP Heaters 13, 14, 15	1. Mechanical Failure	Loss of thermal efficiency. Potential for thermal shock of steam generator.	Attempt to close valve.

Table C7. Feedwater regulating system FMEA

Failure	Possible Causes	Effects	Remedial Actions
1. Steam Flow Transmitter (FT1011, 1021) Fails High	1. Capacitance Bridge Circuit Failure 2. Capacitor Plates Fail	Erroneous transmitter signal will cause controller to open valve wider to increase the rate of feedwater flow. This may result in steam generator overfill.	Operator should manually control the valve when level rises. Repair transmitter.
2. Steam Flow Transmitter (FT1011, 1021) Fails Low	See Above	Erroneous transmitter signal will cause controller to modulate valve closed to decrease the feedwater flow rate. This may result in insufficient flow to the steam generator and RCS undercooling without auxiliary feed initiation.	Operator should manually control the valve when level falls. Repair transmitter. Initiate auxiliary feed if necessary.
3. Feedwater Flow Transmitter (FT1111, 1121) Fails High	See Above	Erroneous transmitter signal will cause controller to modulate valve closed to decrease the feedwater flow rate. This may result in insufficient flow to the steam generator and RCS undercooling without auxiliary feedwater initiation.	Operator should manually control the valve when level falls. Repair transmitter. Initiate auxiliary feed if necessary.
4. Feedwater Flow Transmitter (FT1111, 1121) Fails Low	See Above	Erroneous transmitter signal will cause controller to open valve to increase	Operator should manually control the valve when level rises. Repair transmitter.

Table C7. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		feedwater flow rate. This may result in steam generator overfill.	
5. SG Level Transmitter (LT1111, 1121 or LT1105, 1106) Fails High	See Above	Erroneous transmitter signal will cause controller to modulate valve closed to reduce feedwater flow rate. This may result in insufficient flow to the steam generator and RCS undercooling without auxiliary feedwater initiation.	Operator should manually control the valve when level falls. Repair transmitter. Initiate auxiliary feed if necessary.
6. SG Level Transmitter (LT1111, 1121 or LT1105, 1106) Fails Low	See Above	Erroneous transmitter signal will cause controller to modulate valve open to increase feedwater flow rate. This may result in steam generator overfill.	Operator should manually control the valve when level rises. Repair transmitter.
7. Feedwater Controller (FC1111, 1121 or (FC105, 1106) Failure Opens Valve	1. Loss of Control Power (Y01 and Y09, Y02 and Y10) Valve Open 2. Electronic Failure	Valve supplies excessive feedwater flow to steam generator causing overfill and RCS overcooling. Potential for carryover to turbine causing turbine erosion exists prior to turbine trip.	Operator should attempt manual control or trip the main feedwater pumps to prevent SG overfill.

Table C7. (continued)

Failure	Possible Causes	Effects	Remedial Actions
8. Feedwater Controller (FC1111, 1121 or LIC1105, 1106) Fails Valve Closed	1. Loss of Control Power (Y01 and Y09, Y02 and Y10) Valve Closed 2. Electronic Failure	Valve fails to supply sufficient feedwater flow to steam generator resulting in RCS undercooling without auxiliary feedwater initiation.	Initiate auxiliary feedwater if manual control can not modulate flow.

Table C8. Main steam system and atmospheric steam dump turbine bypass control system FMEA

Failure	Possible Causes	Effects	Remedial Actions
1. Atmospheric Steam Dump Valves (MS-3938, 3939) Fail to Open When Conditions Warrant	1. Mechanical failure 2. Reactor regulating system Tav error signal not received 3. I/P converter failure 4. Loss of dc bus 11	Significant failure if it becomes necessary for these valves to open in response to a small LOCA. RCS could not be depressurized.	Manually open valve, if possible.
2. Atmospheric Steam Dump Valves (MS-3938, 3939) Fail to Close	1. Mechanical failure 2. Solenoid valves (3938-SV, 3939) fail to close preventing isolation of hp instrument air 3. Tav error signal failure 4. I/P converter failure	Minimal depressurization of steam generator because each valve is only capable of relieving 2.5% of full power steam flow.	Manually close valve, if possible.
3. Atmospheric Steam Dump Valves (MS-3938, MS-3939) Close Inadvertently	1. Mechanical failure 2. Loss of dc bus 11 3. I/P converter failure	Minimal impact provided turbine bypass and code safety valves are available to relieve pressure.	Manually open valve, if possible.
4. Atmospheric Steam Dump Valves (MS-3938, 3939) Open Inadvertently	1. Mechanical failure 2. Spurious Tav error signal 3. E/P converter failure	Minimal depressurization of steam generator because each valve is only capable of relieving 2.5% of full power steam flow.	Manually close valve, if possible.

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
5. Atmospheric Steam Dump Valves (MS-3938, 3939) Fails to Quick Open	1. Mechanical failure 2. Loss of 125 VDC unit control panels 3. Solenoid valves (3938-SV, 3939) fail to open to permit higher instrument air pressure 4. Main Turbine Control System fails to send quick open signal	Minimal impact. Turbine bypass and code safety valves may be challenged.	Verify turbine bypass or code safety relieve S.G. pressure.
6. Auxiliary Feed Pump Steam Supply Valve (MS-4070) Fails to Open	1. Mechanical failure 2. Fails to receive AFAS signal 3. Fails to receive 125 VDC control power	Important failure mode regarding RCS undercooling. Motor-driven auxiliary feed pumps are assumed to be available to supply feedwater to SG.	Manually open valve, if possible. Manually open bypass valve.
7. Auxiliary Feed Pump Steam Supply Valve (MS-4070) Inadvertently Closes	1. Mechanical failure	Same as above.	Manually open valve, if possible.
8. Auxiliary Feed Pump Steam Supply Valve (MS-4070) Inadvertently Opens	1. Mechanical failure 2. Loss of air pressure 3. Spurious AFAS signal	Minimal impact on RCS and secondary system. Analysis assumes main feedwater isolation valves are closed and main SGFP is runback. Otherwise, potential exists for SG overcooling and safety injection.	Manually close valves, if possible.

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
9. Main SGFP Steam Stop Valve Closes	1. Mechanical failure	Minimal impact SGFP trips. SG level drops until SG level initiates AFAS. Auxiliary feedwater pumps provide SG heat removal. Reactor trips on low SG level.	
10. Main SGFP Turbine Steam Control Valve Closes	1. Mechanical failure	Same as above.	
11. Valve MS-260 Closes	1. Mechanical failure	Main Steam fails to supply steam to steam seal regulator. Minimal impact. Loss of steam seal will cause trip of both the main turbine and the SGFP turbines.	
12. Main Steam to MSR Steam Supply Isolation Valves (MS-4025, 4026) Fail Closed	1. Mechanical failure 2. Inadvertent signal	Main Steam fails to supply steam to moisture separator reheaters. Minimal impact. Reduced power from low pressure turbines.	Manually open valves, if possible.
13. Turbine Bypass Valves (MS-3940, 3942, 3944, 3946) Fail to Open	1. Mechanical failure 2. Fails to receive signal from SG outlet pressure and reactor regulating system 3. I/P converter failure	Significant failure if it becomes necessary for the Turbine Bypass Valves to open in response to a small LOCA. RCS could not be depressurized.	Manually open valve, if possible.

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	4. Loss of dc bus 11 5. Pressure transmitter fails 6. Signal auctioneering circuit (PY-4056) fails		
14. Turbine Bypass Valves (MS-3940, 3942, 3944, 3946) Fail to Close	1. Mechanical failure 2. Solenoid valves (MS-3941, 3943, 3945, 3947) fail to close preventing isolation of instrument air 3. Tav error or pressure signal failure 4. I/P converter failure 5. Control circuit failure	Substantial depressurization of steam generator which could result in initial RCS overcooling. Each turbine bypass valve is able to pass 10% of full power steam flow. If depressurization continues, MSIVs will automatically close isolating the bypass valves.	Manually close valve, if possible. Close isolation valves or manually initiate MSIV closure.
15. Turbine Bypass Valves (MS-3940, 3942, 3944, 3946) Close Inadvertently	1. Mechanical failure 2. Loss of dc bus 3. I/P converter failure	Minimal impact provided atmospheric dump and code safety valves are available to relieve pressure.	Manually open valve, if possible.
16. Turbine Bypass Valves (MS-3940, 3942, 3944, 3946) Open Inadvertently	1. Mechanical failure 2. Spurious Tav error or pressure signal 3. I/P converter failure 4. Control circuit failure	Substantial depressurization of steam generator which could result in initial RCS overcooling. Each turbine bypass valve is able to pass 10% of full power steam flow. If depressurization continues, MSIVs will auto-	Manually close valve, if possible. Take necessary procedures to control and reduce depressurization including manually closing isolation valves.

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		matically close isolating the bypass valves.	
17. Turbine Bypass Valves (MS-3940, 3942, 3944, 3946) Fails to Quick Open	1. Mechanical failure 2. Loss of 125 VDC unit control panels 3. Solenoid valves (3941-CV, 3943, 3945, 3947) fail to open to permit higher instrument air pressure 4. Main Turbine Control System fails to send quick open signal	Minimal impact atmospheric dump and code safety valves may be challenged.	Verify atmospheric dump and code safety valves relieve SG pressure.
18. Solenoid Valves (MS 3940-SV, 3942, 3944, 3946) Fail to Prevent Turbine Bypass Valves from Opening When Condenser Vacuum is Low or Cause Quick Close	1. Mechanical failure 2. Fails to receive low condenser vacuum signal	May damage condenser. Minimal impact on RCS due to availability of code safety valves.	
19. Code Safety Valves (MS-3092 thru 4007) Fail to Open	1. Mechanical failure	Important event but unlikely to happen. Sixteen valves are available to open two-at-a-time to relieve SG pressure. The sixteen	Manually open valve, if necessary.

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		valves have sequentially higher setpoints. Turbine bypass and steam dump valves must also fail for this to be a significant event. If lower setpoint valves fail, higher setpoint valves will relieve pressure.	
20. Code Safety Valves (MS-3092 thru 4007) Opens Inadvertently or Fails to Close	1. Mechanical failure	Significant event due to rapid depressurization of main steam header which may result in RCS overcooling.	Manually close valve, if necessary.
21. Main Steam Line Drainage System Fails to Drain	1. Valves fail closed due to mechanical failure 2. Loss of control power to motor operated valves	Insignificant failure. Most valves can be opened manually. Complete loss of all drainage is unlikely. All drain flow is a gravity flow to condenser or blowdown tank.	
22. Auxiliary Blowdown Pumps (11, 12) Fail	1. Mechanical failure 2. Loss of electric power to pump from motor control center	Insignificant failure. Auxiliary Blowdown Tank would overfill and condensate would flow to plant drain.	

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
23. Main Steam Isolation Valve (MS-4043, 4048) Closes Inadvertently	1. Mechanical failure of valve 2. Spurious SGIS signal 3. Low pressure pumping unit is unable to hold valve open	Insignificant event because atmospheric dump and code safety valves are available to relieve main steam pressure. Main steam pressure should normally be sufficient to hold valve open, low pressure pumping unit is normally only necessary to cause the valve to open from the closed position. Turbine trip would result.	
24. Main Steam Isolation Valve (MS-4043, 4048), Fails to Close	1. Mechanical failure of valve 2. High pressure pumping unit failure causes accumulator pressure to decrease below the pressure necessary to close valve 3. Failure in the accumulator module 4. Failure in the cylinder module 5. Failure in the valve module 6. 125 VDC power failure 7. SGIS signal not received due to circuitry failure	Significant event if a steam generator isolation signal actuates the valves to close. The inventory in the SG would rapidly blowdown through a rupture in the main steam header. Significant impact on RCS undercooling.	

Table C8. (continued)

Failure	Possible Causes	Effects	Remedial Actions
25. Main Steam Isolation Valve (MS-4043, 4048) Fails to Open	1. Mechanical failure of valve 2. Low pressure pumping unit failure 3. High pressure pumping unit is signaled to close the valve	Insignificant event because plant is at low power level when valves are normally closed. Atmospheric dump and code safety valves are available to relieve main steam pressure. Once opened main steam pressure will hold valve open.	

Table C9. Component cooling system FMEA

Failure	Possible Causes	Effects	Remedial Actions
Fails to Supply Cooling Water to Loads			
1. Loss of Component Cooling Water to Reactor Coolant Pump Seals		Upon detection of high RC pump seal controlled bleedoff temperature, which would occur after a loss of component cooling water to the pump seals, the operator tor is instructed to trip the pumps. Failure to trip the pumps under these conditions is assumed to result in failure of the pump seals. Rupture of the pump seals constitutes a small loss of coolant accident (LOCA) safety systems including HPSI and LPSI will be challenged. RCS undercooling may result due to the LOCA.	Re-open component cooling system valves to response flow possible. If component cooling water flow cannot be restored, trip RC pump prior to exceeding temperature limits of pump seals. If the seal fails, follow procedure for a small LOCA.
a. All four pumps	1. CC-283 closes 2. CC-284 closes 3. CV-3832 closes 4. CV-3833 closes 5. Loss of control power to SV-3832 or 3833 6. Loss of pneumatic supply to SV-3832 or 3833 7. SV-3832 closes 8. SV-3833 closes		
b. On one pump:	Operator fails to trip pump after one of the following:		
Pump 11A	CC-170 or 171 closes		
Pump 11B	CC-173 or 174 closes		
Pump 12A	CC-176 or 177 closes		
Pump 12B	CC-179 or 180 closes		

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
2. Fails to Supply Water to RCP Thermal Barrier	1. CV 3832 or 3833 Closes 2. CC 284 or 289 Closes 3. SV 3832 or 3833 Closes 4. Component Cooling System Failure 5. Loss of Instrument Air 6. Loss of Control Power 7. Supply Return Valves Close	Fails to cool labyrinth passageway in body of RCP. May require pump trip to prevent damage. Normal flow is 28 gpm.	Adjust throttle setting on component cooling heat exchanger. Valve-in backup heat exchanger. Start redundant component cooling pump. Cooling must be restored in 10 minutes to prevent pump damage.
3. Fails to Supply Cooling Water to RCP Upper/Lower Bearing Oil Coolers	1. CV 3832 or 3833 Closes 2. CC 384 or 389 Closes 3. SV 3832 or 3833 Closes 4. Component Cooling System Failure 5. Loss of Instrument Air 6. Loss of Control Power 7. Supply Return Valves Close	Fails to cool RCP motor bearing lube oil coolers. May require pump trip to prevent damage. Normal flow 150 gpm to upper bearing cooler and 5 gpm to lower bearing cooler.	Adjust throttle setting on component cooling heat exchanger. Valve-in backup heat exchanger. Start redundant component cooling pump. Cooling must be restored in 10 minutes to prevent pump damage.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
4. Fails to Supply Cooling Water to Letdown Heat Exchanger	Component Cooling System Failure	Fails to cool heat exchanger to a temperature suitable (below 145°F) for long term operation of the purification system. Above 145°F, the ion exchanger bypass valve shifts to bypass operation to protect the ion exchanger resins.	Manually control letdown heat exchanger component cooling outlet control valve to maintain temperature at 120°F.
5. Fails to Supply Cooling Water to Control Element Drive Mechanism	1. CV 3832 or 3833 Closes 2. CC 284 or 289 Closes 3. SV 3832 or 3833 Closes 4. Component Cooling System Failure 5. Loss of Instrument Air 6. Loss of Control Power 7. Supply Return Valves Close	Loss of component cooling does not have a drastic effect on CEDM unless air flow is also lost. Loss of component cooling for sustained periods can shorten CEDM coil life. Eventually due to degradation of the coil, the CEAs would drop due to lack of sufficient current and the reactor would shutdown.	Restore component cooling water flow to CEDM coolers.
6. Fails to Supply Cooling Water to Reactor Vessel Support Coolers	1. CV 3832 or 3833 Closes 2. CC 284 or 289 Closes 3. SV 3832 or 3833 Closes	Bearing surfaces and structural concrete exceed allowable working temperatures. 40-year life expectancy is reduced due to extended overheating.	Restore component cooling water flow to reactor vessel support coolers.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	4. Component Cooling System Failure		
	5. Loss of Instrument Air		
	6. Loss of Control Power		
	7. Supply Return Valves Close		
7. Fails to Supply Cooling Water to Steam Generator Support Coolers	1. CV 3832 or 3833 Closes	Bearing surfaces and structural concrete exceed allowable working temperatures. 40-year life expectancy would be reduced due to extended overheating.	Restore component cooling water flow to steam generator vessel supports.
	2. CC 284 or 289 Closes		
	3. SV 3832 or 3833 Closes		
	4. Component Cooling System Failure		
	5. Loss of Instrument Air		
	6. Loss of Control Power		
	7. Supply Return Valves Close		
8. Fails to Supply Cooling Water to Shutdown Cooling Heating Exchangers During:	1. CC 264 or CC 261 Closes	Inability to reach shutdown temperature using heat exchangers. Alternate method of cooldown should be used until component cooling again becomes available.	Restore component cooling to shutdown cooling heat exchangers.
	2. CC 261 or CC 266 Closes		

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
1. Plant Cooldown	3. Component Cooling System Failure	- Requires two pumps and two heat exchangers for plant cooldown (300 to 120°F).	
	4. Outlet Control Valve (CV 3830 or CV 3828) Fails to Open		
2. Post LOCI Cooldown		- Requires one pump and two heat exchangers for post LOCI cooldown	
3. Cold Shutdown		- Requires one pump and one heat exchanger for cold shutdown	
9. Loss of Component Cooling Water to HPSI and LPSI Pumps		Pumps are designed to operate for two hours without comopnent cooling water. Loss of component water for periods greater than two hours is assumed to fail HPSI and LPSI. HPSI and LPSI are safety systems designed to provide core heat removal during emergency operation.	Re-open valves if possible. If safety injection is required and cooling water flow cannot be restored, attempt to rotate the pumps in operation.
a. All HPSI and LPSI pumps affected	Mechanical failure CC-258 closes		
b. HPSI 11 and 12 and LPSI 11 affected	Mechanical failure CC-270 closes		
c. HPSI 13 and LPSI 12 affected	Mechanical failure CC-242 closes		

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
10. Fails to Supply Cooling Water to Containment Penetrations Coolers for Main Steam Lines, Feedwater Lines, Steam Generator Blowdown Lines, Reactor Coolant Letdown Lines, Reactor Coolant Sampling	1. CC 163, CC 270, or CC 111 Closes 2. Component Cooling System Failure 3. Supply or Return Valves to Individual Coolers Fail	Failure of the component cooling system to supply cooling water to the coolers will not result in abrupt failure of containment penetration.	Restore component cooling water flow to containment penetration coolers.
11. Fails to Supply Cooling Water to Reactor Coolant Waste Evaporator	1. CC 457 or CC 458 Closes 2. Component System Failure 3. Individual Supply and Return Valves Closes	Inability to condense vapor in the evaporator concentrator condenser. Evaporator requires extensive cooling, so during a transient the cooling water supply to evaporator is isolated, providing more cooling water for safety needs. No significant impact on plant safety.	Operator restores component cooling water to RC waste evaporator.
12. Fails to Supply Cooling Water to Miscellaneous Waste Evaporator	1. Individual Supply or Return Valve Closes 2. Component Cooling System Failure	Inability to condense vapor in concentrator condenser. Evaporator requires extensive cooling, so during a transient cooling water is isolated, providing addi-	Operator restores component cooling water to the miscellaneous waste evaporator.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	3. CC 457 or CC 458 Closes	tional cooling water for safety needs. No significant impact on plant safety.	
13. Fails to Supply Cooling Water to: 1. Distillate Cooler 2. Vacuum Pump Seal Water Cooler 3. Vacuum Pump Discharge Gas Cooler	1. Supply or Return Valve Closes 2. Component Cooling System Failure	Fails to cool distillate prior to discharge to waste monitor tank. Fails to cool seal water prior to its discharge into the vacuum pump suction. Fails to cool vapors prior to their discharge to the Waste Gas System. Isolated on CIS. Represents major non-safety load or component cooling.	Operator restores cooling water to the coolers, if possible.
14. Fails to Supply Cooling Water to Waste Gas Compressors	1. Supply or Return Valve Closes 2. Component Cooling System Failure 3. Solenoid Valve SV 2203 (SV 2205) Fails to Open 4. High Pressure Signal Starts Compressor but Doesn't Open Valve (SV 2203)	Cooling water is absolutely necessary to prevent overheating of compressors. If cooling is lost, operator should secure waste gas compressor.	Secure waste gas compressor and repairs component cooling system.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
15. Fails to Supply Cooling Water to: 1. Reactor Coolant Drain Tank Heat Exchanger 2. Degasifier Vacuum Pump Accumulator	1. Supply or Return Valve Closes 2. Component Cooling System Failure	Reactor coolant drain tank overheats and overpressurizes. Drain water flashes to steam. Failure to cool incoming gases results in loss of seal to the vacuum pump. Vacuum pump will then overheat if not secured by the operator.	Restore cooling water to components as quickly as possible.
16. Fails to Supply Cooling Water to Sample Coolers for Miscellaneous Waste Steam Generator Reactor Coolant	1. Supply or Return Valves Closes 2. Component Cooling System Failure	No cooling of samples to acceptable temperatures for chemical analysis. Operator will need to wait for sample to cool before chemical analysis can be performed. Personnel injury possible due to handling of hot samples.	Provide an alternative method for cooling sample.
17. Fails to Supply Cooling Water to Gas Analyzing Unit	1. Supply or Return Valves Closes 2. Component Cooling System Failure	Fails to cool hot oxygen and hydrogen samples to acceptable temperatures for accurate analysis by the gas analyzers.	Provide component cooling water from Unit 2 component cooling water system.
18. Fails to Supply Cooling Water to Steam Generator Blowdown Radiation Monitoring Unit Sample Cooler	1. Supply or Return Valves Closes 2. Component Cooling System Failure	Fails to reduce temperature of blowdown sample below 140^{o}F necessary for proper operation of radiation monitor unit.	Restore cooling, if possible.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
<u>Component Cooling System Failures Which Fail Supply of Cooling Water to Loads</u>			
19. Component Cooling Pumps 11, 12, 13 Fail	1. Loss of Electric Power from Unit Buses 11A, 14A, 11B or 14B 2. Mechanical Failure 3. Pump Fails to Receive Start Actuation Due to Circuitry Failure	Normal operation requires one component cooling water pump to run as designed. Although plant cooldown is normally accomplished using two pumps, one pump could cooldown but it would take a longer time. Pump 13 has two sources of electric increasing system reliability. Failure of all three pumps will adversely impact numerous components throughout the plant. Two pumps upon SIAS.	Upon failure of operating pump, operator should start standby pump. If third pump (13) does not start, alternate power breaker should be closed in. Failure to supply cooling water to some loads may require reactor trip.
20. Pump Suction Valves (CC 111, 112), (CC 116, 117), (CC 121, 122) Closes	Mechanical Failure	Component cooling water system includes a normal and standby header for both the supply and return lines. If one of the headers becomes inoperable (valve failure), system operation can continue on a single header with no significant degradation of performance, i.e., both supply or both return valves must fail.	Manually open valve if possible.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
21. Pump Discharge Valves (CC 113, 114), (CC 118, 119), (CC 123, 124) Closes	Mechanical Failure	Component cooling water system includes a normal and standby header for both the supply and return lines. If one of the headers becomes inoperable (valve failure), system operation can continue on a single header with no significant degradation of performance, i.e., both pump valves must fail.	
22. Component Cooling Head Tank Fails to Provide Net Positive Suction Head and Surge Volume	1. Level Switch Fails to Provide Tank Makeup 2. CC 101 and 102 Fail Closed	Unlikely event in which head tank fails to supply head to component cooling return headers causing pump cavitation.	Manually open bypass valve permitting makeup from the demineralized water system or the condensate system.
23. Component Cooling System Heat Exchangers 11, 12 Fail	1. Outlet Valve CC 149, 156 Fail Closed 2. Salt Water System Fails to Cool Heat Exchanger	Loss of cooling water flow will cause failure of strategic components in 2 hours. If only one heat exchanger is required, the failed heat exchanger should be isolated and the standby heat exchange should be valved into operation. Loss of salt water cooling will degrade the ability of the component cooling system to cool strategic components.	Operator should valve in standby heat exchanger. May also be necessary to isolate the larger loads such as the waste evaporators.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
24. Header Valve Failures:	Mechanical Failure Causes Valve to Close		Operator manually reopens valve.
CC 147 and 148		Fails supply of component cooling water to heat exchanger 12.	
CC 154 and 155		Fails supply of component cooling water to heat exchanger 11. All four supply valves must fail closed to fail component cooling water supply to heat exchangers.	
CV 3824		Fails flow from heat exchanger 11 to cooling loads.	
CV 3826		Fails flow from heat exchanger 12 to cooling loads. For failure to be significant, valve must fail on the associated operating heat exchanger.	
25. Bypass Valve Failures: CV 3823 CV 3825	Mechanical Failure Causes Valve to Open	Bypass valve fails open causing component cooling water to bypass the heat exchanger. This causes degraded operation of component cooling system.	Operator manually closes valve.

Table C9. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		For failure to be significant, valve must fail on the associated operating heat exchanger and flow bypassed must be significant.	
26. Header Valve Failure: CC 163, 162	Mechanical Failure Causes Valve to Close	Both valves must fail closed to cause a loss of component cooling water to the loads.	Operator manually reopens valve.
<u>Other Failures</u>			
27. Component Cooling Additive Tank Fails	1. CC 141 and 142 Fail to Open 2. CC 143 Fails to Open	Failure to add chemicals to component cooling system via the additive tank will result in increased corrosion of the components and piping in the component cooling system. Heat transfer across fouled surfaces will be reduced.	If valves are source of problem, attempt to manually open.

Table C10. Service water system FMEA

Failure	Possible Causes	Effects	Remedial Actions
<u>Service Water Header Failures</u>			
1. Service Water Pumps 11, 12, 13 Trip	1. Mechanical Failure 2. Loss of Electric Power from 4 kV Bus 11 for Pump 11, 4 kV Bus 14 for Pump 12, and both 4 kV Buses 11 and 14 for Pump 13 3. Supply or Return Valves Fail Closed	Significant failure because it degrades heat removal from important plant components including the diesel generators and the instrument air compressors. Two pumps are required to operate so one pump is placed in standby. The redundancy incorporated into the design permits operation of pump 13 from either bus. Unlikely that two pumps would fail simultaneously.	Verify automatic start of standby pump. If pump 13 does not start, align contacts to other bus.
2. Service Water Heat Exchanger 11, 12 Fails	1. Mechanical Failure 2. Salt Water System Header Failure 3. Inlet or Outlet Valves Fail Closed	Significant failure because it degrades heat removal from important plant components. Plant may be temporarily operated with just one heat exchanger during normal operation. During an emergency some loads would be isolated, permitting longer operation with only one heat exchanger.	Re-open valves or repair heat exchanger if possible.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
3. Service Water Head Tank 11, 12 Fails to Provide Suction Head	1. SRW-1579 Fails to Open and Bypass Valve Fails to Open 2. LS-1529 Fails to Open SRW-1579 and Bypass Valve Fails to Open 3. Solenoid Valve SV-1579 Fails to Close	Failure to provide makeup to head tanks may result in the loss of net positive suction head to the service water pumps. Loss of suction head will fail pumps.	Operator should manually open valve to control water level in head tank.
4. Service Water Additive Tank Fails Chemical Addition	Valves Fail to Open	Insignificant failure with respect to plant response to a transient.	
<u>Loss of Cooling Water to System Loads</u>			
5. Loss of Service Water to Emergency Diesel Generator:		Loss of service water to an emergency diesel generator will result in diesel generator failure. The two Calvert Cliffs units share 3 diesels. Supply header 11 can supply service water to either diesel 11 or 12. Supply header 12 can supply diesel 12 or 21. Supply header 21 can supply diesel 11 or 12. Supply header 22 can supply diesel 21 and 12.	If one supply header to a particular diesel is unavailable, operator should open valves to supply diesel with an alternate source of cooling water.
No. 11 Diesel	1. 1-CV-1587 Fails to Open a. Mechanical Failure b. Diesel Start Signal Not Received Due to Circuitry Failure c. Controller PDIC-1587 Closes Valve		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	2. One of Two Manual Valves Fail Closed 3. Service Water Header Failures	service water failures. This redundancy reduces the probability of loss of diesel power due to service water failures.	
No. 21 Diesel	1. 2-CV-1587 Fails to Open a. Mechanical Failure b. Diesel Start Signal Not Received Due to Circuitry Failure c. Controller PDIC-1587 Closes Valve		
	2. One of Two Manual Valves Fail Closed		
	3. Service Water Header Failures		
No. 12 Diesel	1. 1 and 2-CV-1645 Fail to Open a. Mechanical Failure b. Pressure Sensors 1/2 PS-1645 Fail		
	2. 1 and 2-CV-1645 Fail to Open a. Mechanical Failure		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	b. Pressure Sensors Prevent Valve from Opening		
	3. 1-CV-1588 Fails to Open a. Mechanical Failure b. Diesel Start Signal Not Received Due to Circuitry Failure c. Controller PDIC-1588 Closes Valve		
	4. Both Manual Supply or Both Return Valves Fail Closed Simultaneously		
	5. Service Water Header Failures		
6. Loss of Service Water to Compressed Air System Components: All Instrument Air and Compressed Air Compressors	1. SRW-181 Fails Closed 2. SRW-183 Fails Closed 3. PCV-1628 Fails Closed	Loss of service water cooling to the compressors or aftercoolers will result in eventual compressor or aftercooler failure. This is a significant failure because pneumatic components must be continuously supplied with instrument air to maintain safe and reliable operation of the plant. Some redun-	Reopen service water supply or return valves if possible.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	4. CV-1637 Fails Closed 5. CV-1639 Fails Closed 6. Service Water Pump 11 Trips 7. Loss of Electric Power From 125 VDC Bus 11 Closes CV-1637 8. Loss of Electric Power From 125 VDC Bus 21 Closes CV-1639	dancy is provided in the compressed air system in the event of component failures. Two instrument air compressors are available, although one is usually all that is required. The Unit 1 plant air compressor is backed up by the Unit 2 plant air compressor. Plant air is also important because it provides breathing air for respirator operation inside containment. Plant air is backed up by breathing air tanks inside containment.	
Plant Compressor 11	1. SRW-197 Fails Closed 2. SV-1636 Fails Closed 3. TCV-1636 Fails Closed		Verify that backup compressors are started when line pressure drops below low limit.
Plant Compressor 11 Aftercooler	1. SRW-199 Fails Closed 2. SV-1635 Fails Closed 3. SRW-200 Fails Closed		
Instrument Air Compressor 11	1. SRW-189 Fails Closed 2. TCV-1630 Fails Closed 3. SV-1630 Fails Closed		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Instrument Air Compressor 11 Aftercooler	1. SRW-191 Fails Closed		
	2. SV-1629 Fails Closed		
	3. SRW-192 Fails Closed		
Instrument Air Compressor 12	1. SRW-193 Fails Closed		
	2. SV-1634 Fails Closed		
	3. TCV-1634 Fails Closed		
Instrument Air Compressor 12 Aftercooler	1. SRW-195 Fails Closed		
	2. SV-1633 Fails Closed		
	3. SRW-196 Fails Closed		
7. Loss of Service Water to Aux. Feed Pump Room A/C Cooler	1. SRW-502 Fails Closed	Extended loss of service water to auxiliary feed pump room coolers is assumed to fail the auxiliary feedwater pumps if they are running. The time to failure cannot be determined using FMEA techniques.	Re-open valve if possible.
	2. PCV-1600 Fails Closed		
	3. SRW-503 Fails Closed		
	4. Service Water Header Failures		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
8. Loss of Service Water to Generator Exciter Air Coolers	1. SRW-286 Fails Closed 2. SRW-289 Fails Closed and SRW 291 Fails to Open 3. SRW-1603-CV Fails Closed and SRW-291 Fails to Open 4. SRW-290 Fails Closed and SRW-291 Fails to Open 5. TIC-1603 Closes CV-1603 and SRW-291 Fails to Open 6. Service Water Header Failures	Loss of service water for extended period is assumed to result in the loss of heat removal from generator exciter and eventual turbine trip. This failure is not expected to have a significant impact on plant response to a transient.	Re-open valve if possible. Verify turbine trip on high exciter temperature.
9. Loss of Service Water to Generator Bus Duct Coolers			
Cooler 12	1. SRW-296 Fails Closed 2. SRW-297 Fails Closed 3. CV-9901 Fails Closed	Loss of service water for an extended period is assumed to result in a turbine generator trip. This failure is not expected to have a significant impact on	Re-open valve if possible.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	4. Service Water Header Failures	plant response to a transient.	
Cooler 11	1. SRW-292 Fails Closed 2. SRW-293 Fails Closed 3. CV-9900 Fails Closed 4. Service Water Header Failures		
10. Loss of Service Water to Turbine Plant Sampling Coolers	1. SRW-270 Fails Closed 2. SRW-271 Fails Closed 3. Service Water Header Failures	Insignificant impact on plant response to a transient.	Re-open valve if possible.
11. Loss of Service Water to Nitrogen Compressor and Aftercooler	1. Manual or Pressure Control Valve Fail Closed 2. SRW-226 Fails Closed 3. Manual Valve Fails Closed 4. Service Water Header Failures	Failure for an extended period is assumed to fail the nitrogen compressor. It does not represent a significant impact on plant operation because Boron Injection Tanks are charged at startup.	Re-open valve if possible.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
12. Loss of Service Water to Degasifier Vacuum Pump	1. SRW-392 Fails Closed 2. SRW-393 Fails Closed 3. Service Water Header Failures	Insignificant failure which will have minimal impact on plant operation.	Re-open valve if possible.
13. Loss of Service Water to Turbine Lube Oil Coolers	1. SRW-252 Fails Closed 2. SRW-256 Fails Closed and SRW-258 Fails to Open 3. SRW-1626-CV Fails Closed and SRW-258 Fails to Open 4. SRW-257 Fails Closed and SRW-258 Fails to Open 5. SRW-253 Fails Closed 6. TIC-1626 Closes CV-1626 and SRW-258 Fails to Open 7. Service Water Header Failures	Loss of service water to coolers is assumed to fail coolers and trip turbine. This failure is not considered to have a significant impact on plant operation.	Re-open valves if possible. Verify turbine trips if lube oil temperature exceeds design limit.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
14. Loss of Service Water to Generator Hydrogen Coolers:	1. SRW-283 Fails Closed and SRW-285 Fails to Open 2. SRW-1608-CV Fails Closed and SRW-285 Fails to Open 3. SRW-284 Fails Closed and SRW-285 Fails to Open 4. TIC-1608 Closes CV-1608 and SRW-285 Fails to Open 5. Service Water Header Failures	Loss of service water is assumed to fail coolers and cause a turbine trip. Failure is not considered to have a significant impact on plant response to a transient.	Re-open valves if possible. Trip or verify turbine trip upon high temperature indication.
Cooler 11	SRW-272 or 273 Fails Closed		
Cooler 12	SRW-274 or 275 Fails Closed		
Cooler 13	SRW-277 or 278 Fails Closed		
Cooler 14	SRW-280 or 281 Fails Closed		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
15. Loss of Service Water to Generator Stator Liquid Coolers:	Service Water Header Failures	Loss of service water is assumed to fail heat removal from generator stator resulting in a turbine trip. Failure is not considered to have a significant impact on plant response to a transient.	Re-open valve if possible. Trip or verify turbine trip on high temperature indication on generator stator.
Cooler 11	SRW-240 or 241 Fails Closed		
Cooler 12	SRW-244 or 245 Fails Closed		
16. Loss of Service Water to Electrohydraulic Control System Oil Coolers	1. SRW-429 Fails Closed 2. SRW-442 Fails Closed and SRW-443 Fails to Open 3. CV-1628 Fails Closed and SRW-443 Fails to Open 4. TIC-1628 Closes CV-1628 and SRW-443 Fails to Open 5. Service Water Header Failures	Loss of service water to oil coolers for an extended period is assumed to fail the EHC system. This failure is expected to have minimal impact on plant operation because one cooler is sufficient to supply cooling requirements and one cooler is available if the operating cooler should fail.	Re-open valve if possible. Open valve on standby cooler.
Cooler 11	SRW-260 Fails Closed		
Cooler 12	SRW-264 Fails Closed		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
17. Loss of Service Water to Main Feed Pump Lube Oil Coolers		Loss of service water cooling to lube oil coolers for an extended period is assumed to trip the main feedwater pump. Trip of pump will result in turbine and reactor trip.	Operator should feed trip of turbine and reactor and verify the initiation of auxiliary feedwater.
Pump 11 Cooler	1. SRW-202 Fails Closed		
	2. SRW-203 and SRW-446 Fail Closed		
	3. SRW-1622-CV and SRW-446 Fail Closed		
	4. SRW-445 and SRW-446 Fail Closed		
	5. TIC-1622 Closes CV-1622 and SRW-446 Fails Closed		
	6. Service Water Header Failures		
Pump 12 Cooler	1. SRW-206 Fails Closed		
	2. SRW-207 and SRW-448 Fail Closed		
	3. SRW-1623-CV and SRW-448 Fail Closed		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	4. SRW-447 and SRW-448 Fail Closed		
	5. TIC-1623 Closes CV-1623 and SRW-448 Fails Closed		
	6. Service Water Header Failures		
18. Loss of Service Water to Circulating Water Priming Pumps Seal Water Coolers:	Service Water Header Failures	Loss of seal water cooling is assumed to fail pumps. Minimal impact on plant operation. Two pumps are normally operating with one pump isolated. Loss of one pump will require the starting of the standby pump.	Re-open failed valves or open isolation valves to standby seal water cooler and start standby pump.
Cooler 11	SRW-234 Fails Closed		
Cooler 12	SRW-236 Fails Closed		
Cooler 13	SRW-238 Fails Closed		
19. Loss of Service Water to Condenser Vacuum Pump Seal Water Coolers:	1. CV-1627 Fails Closed 2. Service Water Header Failures	Loss of service water is assumed to fail pumps. Minimal impact on plant operation because only two of four pumps are operating. Others are in standby. Third pump (1st standby) is constantly receiving cooling water.	Re-open valve if possible. Open valves and start the standby pump, if running pump fails.
Cooler 11	SRW-210 Fails Closed		
Cooler 12	SRW-214 Fails Closed		
Cooler 13	SRW-218 Fails Closed		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
Cooler 14	SRW-222 Fails Closed		
20. Loss of Service Water to Condensate Booster Pump Lube Oil and Seal Water Coolers	Service Water Header Failures	Loss of service water is assumed to fail the condensate booster pump. This failure will have minimal impact on plant operation since only 2 of 3 booster pumps are required for normal operation.	Re-open valve if possible. Verify standby pump starts, if not already running.
Lube Oil Cooler 11	1. Manual Valve Fails Closed		
	2. TCV-1619 Fails Closed		
Lube Oil Cooler 12	1. Manual Valve Fails Closed		
	2. TCV-1620 Fails Closed		
Lube Oil Cooler 13	1. Manual Valve Fails Closed		
	2. TCV-1621 Fails Closed		
Seal Water Cooler 11A and 11B	1. Manual Supply Valves Fail Closed		
	2. Manual Return Valves Fail Closed		
Seal Water Cooler 12A and 12B	1. Manual Supply Valves Fail Closed		

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	2. Manual Return Valves Fail Closed		
Seal Water Cooler 13A and 13B	1. Manual Supply Valves Fail Closed		
	2. Manual Return Valves Fail Closed		
21. Loss of Service Water to Spent Fuel Pool Heat Exchangers	1. CV-1597 Fails Closed a. Mechanical Failure b. Loss of Instrument Air c. Inadvertent CSAS	Extended failure of the service water to the spent fuel pool heat exchangers will cause the pool temperature to rise above the design temperature. The impact of this failure on the operating reactor and power systems will be minimal. Substantial boiling would have to occur before criticality would take place. Makeup water sources are assumed to mitigate a significant event.	Manually re-open valves to restore service water flow to heat exchanger.
	2. CV-1596 Fails Closed a. Mechanical Failure b. Loss of Instrument Air c. Inadvertent CSAS		
	3. Manual Valves Close Due to Mechanical Failures		
	4. Service Water Header Failures		
22. Loss of Service Water to Containment Coolers:	1. Service Water Header Failures	Significant failure if more than one cooler was to fail at one time. However, this represents an unlikely	Re-open valves if possible or open other header supply valve to the affected cooler.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
11, 12	1. CV-1581, 1583 Fails Closed 2. CV-1584, 1586 Fails Closed 3. Supply Header 11 Failure 4. Manual Valves Fail Closed	event. These coolers provide post accident heat removal from the containment. Significant redundancy is available in this system because either header can be used to supply any cooler. Only 3 coolers are necessary for heat removal following a LOCI.	
13, 14	1. CV-1589, 1592 Fails Closed 2. CV-1591, 1594 Fails Closed 3. Supply Header 12 Failure 4. Manual Valves Fail Closed		
23. Loss of Service Water to Blowdown Recovery Heat Exchanger 12	1. SRW-640 Fails Closed Due to Mechanical Failure 2. SRW-522 Fails Closed Due to Mechanical Failure	Insignificant failure because another heat exchanger, piped in series, is cooled by condensate. Failure to adequately cool blowdown might impact ion exchangers.	Re-open supply and return valves if possible.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
	3. Service Water Header Failures		
24. Loss of Service Water to Turbine Building Components (compressors, vacuum pump seal water coolers)	1. SRW-1600-CV Fails Closed 2. SRW-1637-CV Fails Closed 3. SRW-1638-CV Fails Closed 4. SRW-1639-CV Fails Closed 5. Service Water Header Failures	These valves can close due to mechanical failure or inadvertent SIAS. This action isolates the turbine building loads. Compressed air system would be impacted.	Re-open supply and return valves if possible.
<u>Other Failures</u>			
25. CV-1582 Fails to Open	1. Mechanical Failure 2. CSAS Circuitry Failure 3. SV-1582 Fails to Close	Fails to provide additional, necessary service water flow to containment coolers following a CSAS.	Open SRW-140.
26. CV-1585 Fails to Open	1. Mechanical Failure 2. CSAS Circuitry Failure 3. SV-1585 Fails to Close	Fails to provide additional, necessary service water flow to containment coolers following a CSAS.	Open SRW-147.

Table C10. (continued)

Failure	Possible Causes	Effects	Remedial Actions
27. CV-1590 Fails to Open	1. Mechanical Failure 2. CSAS Circuitry Failure 3. SV-1590 Fails to Close	Fails to provide additional, necessary service water flow to containment coolers following a CSAS.	Open SRW-154.
28. CV-1593 Fails to Open	1. Mechanical Failure 2. CSAS Circuitry Failure 3. SV-1593 Fails to Close	Fails to provide additional, necessary service water flow to containment coolers following a CSAS.	Open SRW-161.
29. CV-1600 Fails Closed	1. Mechanical Failure 2. Inadvertent SIAS	Loss of service water to Turbine Building components.	Re-open valve.
30. CV-1638 Fails Closed	1. Mechanical Failure 2. Inadvertent SIAS	Loss of service water to Turbine Building components.	Re-open valve.

Table C11. Salt water system FMEA

Failure	Possible Causes	Effects	Remedial Actions
Salt Water Header Failure			
1. Salt Water Pump (11, 12) Trips	1. Mechanical Failure 2. Loss of Electric Power to kV Bus 11, 14	During normal operation, two pumps are required to supply cooling loads. Following a LOCI, one pump is able to supply cooling water requirements, however two pumps start on SIAS. Minimal impact is expected from this failure, due to the presence of pump 13 which can receive power from either bus 11 or 14.	Assure standby pump starts after primary pump trips. Operator may need to change bus to which pump 13 is aligned.
2. Salt Water Pump 13 Fails to Start On Demand	1. Mechanical Failure 2. Pump 13 Contacts are Aligned to a Bus Without Electric Power	Minimal problem. During normal operation, shutdown would be required if pump 11, 12 had failed and pump 13 failed to start. Following a LOCI, only one salt water is required.	Assure that pump 13 is aligned to a powered bus.
Failure to Supply Loads			
3. Loss of Salt Water Cooling to Component Cooling Water HX 11, 12	1. SW 5160, 5162 CV Closes 2. SW 5206, 5208, or 5163 Closes 3. Salt Water Pump Trip	Substantial impact on Component Cooling System due to loss of cooling to the component cooling heat exchanger. Time-to-failure for components serviced by the component cooling system can	If salt water cooling is lost to only one component cooling HX, the operator should verify that the operating component cooling HX has adequate cooling water. If cooling RCP pump seals is lost, trip pumps.

Table C11. (continued)

Failure	Possible Causes	Effects	Remedial Actions
		not be determined using FMEA techniques. Loss of component cooling to RCP seals will cause small LOCA.	
4. Loss of Salt Water Cooling to Circulating Water Pump Seals	1. Valve Failure 2. Salt Water System Header Failure	Circulating water system pump trip which will ultimately result in a turbine trip on high condenser temperature.	Operator should trip turbine following circulating water pump trip.
5. Loss of Salt Water to Condenser Tube Bulleting System	1. Valve Failure 2. Salt Water System Header Failure	Temporary inability to clean condenser tubes will have no significant effect on plant operation.	Repair valve or component as necessary.
6. Loss of Salt Water Cooling to Service Water Heat Exchanger 11, 12	1. Valve Failure 2. Salt Water System Header Failure	Substantial impact on Service Water System due to the loss of cooling to the service water heat exchanger. Time-to-failure for components serviced by the Service Water System can not be determined using FMEA techniques. Loss of service water will fail diesel generators.	If salt water cooling is lost to only one service water system heat exchanger, the operator should verify that the operating service water system has adequate cooling water.

Table C11. (continued)

Failure	Possible Causes	Effects	Remedial Actions
7. Loss of Salt Water Cooling to ECCS Pump Room Air Coolers	1. Inlet Valve Closes 2. Salt Water System Header Failure 3. Inlet Valve Fails to Open 4. Outlet Valve Fails to Open 5. Outlet Valve Closes	HPSI and LPSI pumps are able to run 2 hours without cooling water. Failure of the room coolers under emergency conditions would cause gradual room heating until electrical components in the room began. Time-to-failure for these components can not be determined using FMEA techniques.	Repair valve or component as necessary.
8. Loss of Salt Water Cooling to Circulating Water Pump Room Air Coolers	1. Valve Failure 2. Salt Water System Header Failure	Loss of room cooling for an extended period will result in electrical component failure which will cause trip of circulating water pumps and eventually the turbine will trip.	Repair valve or header.
9. Loss of Salt Water to Water Jet Exhauster	1. Valve Failure 2. Salt Water System Header Failure	Loss of salt water to jet exhauster will prevent startup of the screen wash system.	Repair valve or header.

Table C12. Instrument air system FMEA

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
1. Air compressor #11 stops when in the SPEED mode	1. Maintenance error 2. Loss of electric power (Bus 11B(ZB)) 3. Controller or instrumentation failure 4. High aftercooler discharge temperature 5. Other	AC #12 will start when pressure decays to 90 psig. If AC#12 is not available then IA pressure will continue to decay to 85 psig when crossconnect valve PA 2061 auto opens and provides PA to the IA header as a backup.	No immediate operator actions required provided AC#12 starts or the PA system provides backup IA as designed. Maintenance corrects problem with AC#11.
2. Air compressor #12 stops when in SPEED mode	SAME AS ABOVE		
3. Aftercooler 11 (12) functions improperly causing high air discharge temperature	1. Low SRW flow due to maintenance error 2. Blocked heat exchange tubes	Associated air compressor trips causing the effects noted in 1. above.	No immediate operator actions required provided AC12(11) is available to provide IA or the PA system provides backup IA as designed. Maintenance corrects problem.

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
4. Aftercooler relief valve sticks open RV2063(2065)	Rust, scale, debris or other contamination in the IA causes valve failure	IA pressure will decrease at a rate proportional to the relief valve opening. At 90 psig the standby IA compressor will start and if pressure continues to decrease the PA crossconnect valve will open at 85 psig. For large failures, reasonably rapid decreases in IA pressure are expected and could result in a total loss of instrument air transient with no action to isolate the failed valve.	The aftercooler with the failed open valve can be isolated with the manual isolation valves.
5. Isolation valve on aftercooler outlet is open and cannot be closed (fails open)	Rust, scale, debris or other contamination in the IA causes valve failure	Aftercooler cannot be isolated; however, no adverse effect unless failure is combined with a second failure.	No immediate operator action required. Maintenance corrects the problem.
6. Isolation valve on aftercooler outlet fails closed	1. Operator/maintenance error 2. Gradual buildup of rust, scale, debris and other contamination closes valve	Effect is to cause loss of IA compressors 11(or 12) which was described in 1 and 2 above. When IA pressure drops to 90 psig the standby air compressor will start.	No immediate operator actions required provided AC12 (or 11) starts or the PA system provides backup IA as designed. Maintenance corrects problem with the valve.

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
7. Isolation valve on air receiver 11(12) inlet is open and cannot be closed (fails open)	Rust, scale, debris or other contamination in the IA causes valve failure	Air receiver cannot be isolated; however, no adverse effect unless this failure is combined with another failure such as air receiver relief valve failure.	No immediate operator actions required. Maintenance corrects problem.
8. Isolation valve on air receiver 11(12) inlet fails closed	1. Operator/maintenance error 2. Gradual buildup of rust, scale, debris or other contamination closes valve	No effect unless air receiver 12(11) is out of service and isolated. If that is the case, the PA compressors must be used to provide IA.	No immediate operator actions required. Maintenance corrects problem.
9. Air receiver relief valve RV2066(2067) sticks open	Rust, scale, debris or other contamination causes valve failure	Same effect as failed open relief valve on an aftercooler which was described above.	Operator can isolate the relief valve by manually closing the air receiver inlet and outlet isolation valves.
10. Isolation valve on air receiver 11(12) outlet is open and cannot be closed	Rust, scale, debris or other contamination causes valve failure	Air receiver cannot be isolated; however, no adverse effect unless this failure is combined with a second failure such as air receiver relief valve failure.	No immediate operator action required. Maintenance corrects problem.
11. Isolation valve on air receiver 11(12) outlet fails closed	1. Operator/maintenance error 2. Gradual buildup of rust, scale, debris or other contamination	No effect unless air receiver 12(11) is out of service and isolated. In that case the PA compressor must be used to provide IA.	No immediate operator actions required. Maintenance corrects problem.

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
12. Cross connect valve PA2061 fails closed	1. Valve controller failure 2. Failure of the pressure transmitter that controls valve opening 3. Gradual buildup of rust, scale, debris or other contamination	No effect on IA system unless this failure is combined with an IA failure that requires the PA system to serve as a backup for the IA system.	No immediate operator action required. Maintenance corrects problem.
13. Cross connect valve PA2061 fails open	1. Valve controller failure 2. Failure of the pressure transmitter that controls valve opening	IA and PA systems will be cross connected; however, this should cause no problem. Manual valves exist on both sides of PA2061 and can be closed if necessary.	No immediate operator action required. Maintenance corrects problem.
14. Isolation valve on inlet to prefilter 11 fails closed	1. Operator/maintenance error 2. Gradual buildup of scale, rust, debris or other contamination	This valve is normally open and the isolation valve in prefilter 12 is normally closed. If this failure occurs, IA pressure will begin to decrease since the IA service header is now isolated from all air compressors. Without prompt operator response, a loss of IA transient can result.	Operator must take one of the following actions: 1. Open the inlet and outlet isolation valves on prefilter 12 or 2. Manage to open the failed closed valve or 3. FCR-81-007 modified the system so that the PA system could supply the IA system downstream of the IA dryer.

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
			This modification is not shown on the drawings available to ORNL but is assumed to exist.
15. Isolation valve on inlet to prefilter II fails open and cannot be closed	Rust,scale, debris or other contamination causes valve failure	Prefilter II cannot be isolated; however, no adverse effect unless this failure is combined with a failure that requires the valve to be closed.	No immediate operator action required. Maintenance corrects problem.
16. Isolation valve on outlet of prefilter II fails closed	SAME AS 14 ABOVE		
17. Isolation valve on outlet of prefilter II fails open and cannot be closed	SAME AS 15 ABOVE		
18. Air dryer II inlet isolation valve fails closed	1. Rust, scale, debris or other contamination causes valve failure 2. Operator/maintenance error	When this valve fails closed, IA pressure will begin to decrease since the IA service header is now isolated from all air compressors. Without prompt operator response, a loss of IA transient can result.	Operator must take one of the following actions: 1. Open the normally closed air dryer bypass valve or 2. Manage to open the failed valve or 3. FCR-81-007 modified the IA system so that the PA system could supply the

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
			IA system downstream of the IA dryer. This modification is not shown on the drawings available to ORNL but is assumed to exist.
19. Air dryer II inlet isolation valve fails open and cannot be closed	Rust, scale, debris or other contamination causes valve failure	No effect on the IA system unless this failure is combined with a second failure that requires the isolation of the air dryer.	No immediate operator action required. Maintenance corrects problem.
20. Isolation valve on outlet of air dryer II fails closed	S A M E A S 1 8 A B O V E		
21. Isolation valve on outlet of air dryer II fails open and cannot be closed	S A M E A S 1 9 A B O V E		
22. Afterfilter II inlet isolation valve fails closed	1. Operator/ maintenance error 2. Rust, scale, debris or other contamination causes valve failure	Afterfilter II isolation valves are normally open and the isolation valves for the redundant afterfilter (#12) are normally closed. If the aftercooler isolation valve fails closed, IA pressure will begin to decrease since the IA service header is now isolated from all air compressors. Without prompt operator response, a loss of IA transient can result.	Operator must open the inlet and outlet isolation valves on after filter 12 or manage to open the failed closed valve.

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
23. Afterfilter II inlet isolation valve fails open and cannot be closed	Rust, scale, debris or other contamination causes valve failure	No effect on the IA system unless the failure is combined with a second failure that requires the isolation of the afterfilter.	No immediate operator action is required. Maintenance corrects the problem.
24. Afterfilter II outlet isolation valve fails closed	SAME AS 22 ABOVE		
25. Afterfilter II outlet isolation valve fails open and cannot be closed	SAME AS 23 ABOVE		
26. Manual valve IA-845 fails closed	I. Operator/ maintenance error	This failure results in loss of IA to the pneumatic valves and instruments in the following systems and areas of the plant: I. Diesel generators II and I2 2. RWT heat exchanger room 3. West penetration room 4. Letdown heat exchanger 5. SFP cooling room 6. Valve compartment 7. CVCS ion exchangers	I. Operations and maintenance personnel attempt to discover and correct the source of the problem. 2. Operator responds as directed by EOP-14, the "Loss of Instrument Air" procedure

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
27. Failure of IA header downstream of valve IA-845 so that IA pressure decreases below 80psig	Mechanical damage to the 2 inch distribution header by maintenance personnel or by equipment failure	This failure results in a total loss of IA transient. Once the plant staff recognizes and diagnoses the failure, the loss of air can be confined to those systems and areas of the plant listed in 26 above.	Close valve IA-845 to isolate failure to the systems and areas of the plant listed under 26 above. Maintenance repairs the failed header.
28. Manual valve IA- fails open and cannot be closed	Gradual buildup of scale, rust, debris or other contamination prevents valve from closing	No effect unless this failure is combined with a second failure such as the IA header failure discussed in 27 above.	No immediate operator action required. Maintenance corrects problem.
29. Manual valve IA-657 fails closed	1. Operator/maintenance error 2. Gradual buildup of rust, scale, debris or other contamination closes valve	This failure results in loss of IA to the pneumatic valves and instruments in the following systems and areas of the plant: 1. Component cooling room 2. ECCS pump room number 11 and 12 3. VCT and BAST rooms 4. Charging pump room 5. Miscellaneous waste receiver tank room 6. Cryogenics room 7. RCW pump room	1. Operations and maintenance personnel attempt to discover and correct the source of the problem. 2. Operator responds as directed by EOP-14, the "Loss of Instrument Air" procedure

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
30. Failure of IA header downstream of valve IA657 so that IA pressure decreases below 80 psig	Mechanical damage to the 2 inch header by maintenance personnel or by equipment failure	This failure can result in a total loss of IA translent. Once the plant staff diagnoses the problem, the air loss can be confined to those systems and areas of the plant listed in 29 above.	Close valve IA657 to isolate failure to those systems and plant areas listed under 29 above. Maintenance repairs the failed header.
31. Manual valve IA 657 fails open and cannot be closed	Gradual buildup of scale, rust, debris or other contamination prevents valve from closing	No effect unless this failure is combined with a second failure such as the IA header failure discussed in 28 above.	No immediate operator action required. Maintenance corrects problem.
32. Manual valve IA 823 fails closed	1. Operator/maintenance error 2. Gradual buildup of rust, scale, debris or other contamination closes valve	This failure results in loss of IA to the pneumatic valves and instruments in the following systems and areas of the plant: 1. Aux. building HVAC area (elevation 5' & 69') 2. Service water pump room 3. East piping penetration room 4. East electrical penetration room 5. Service water head tank area 6. Main plant area 7. Battery vent area 8. Component cooling head tank 9. Access control HVAC	1. Operations and maintenance personnel attempt to discover and correct the source of the problem. 2. Operator responds as directed by EOP-14, the "Loss of Instrument Air" procedure

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
		10. I&C shop 11. Plant computer 12. Blowdown tank area 13. RCW waste evaporator 14. Miscellaneous waste evaporator 15. Fuel upender	
33. Failure of IA header downstream of valve IA823 so that IA pressure decreases below 80psig	Mechanical damage to the 2" header by maintenance personnel or by equipment failure	This failure can result in a total loss of IA transient if not quickly diagnosed. Once the plant staff recognizes and diagnoses the problem, the loss of air can be confined to those systems and areas of the plant listed in 32 above.	Close valve IA823 to isolate the failure to those systems and plant areas listed under 32 above. Maintenance repairs the failed header
34. Manual valve IA 823 fails open and cannot be closed	Gradual buildup of scale, rust, debris or other contamination prevents valve from closing	No effect unless combined with a second failure such as the IA header failure discussed in 33 above.	No immediate operator action required. Maintenance corrects the problem.
35. Manual valve IA 214 fails closed	1. Operator/maintenance error 2. Gradual buildup of rust, scale, debris or other contamination closes valve	This failure results in loss of IA to the pneumatic valves and instruments in the following systems and areas of the plant: 1. Caustic storage tank 2. Make up demineralizers 3. Condensate polishers	1. Operations and maintenance personnel attempt to discover and correct the source of the problem. 2. Operator responds as directed by EOP-14, the "Loss of Instrument Air" procedure

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
36. Failure of IA header downstream of manual valve IA214 so that IA pressure decreases below 80psig	Mechanical damage to the 2" header by maintenance personnel or by equipment failure	This failure can result in a total loss of IA transient if not quickly diagnosed. Once the plant staff recognizes and diagnoses this problem, the loss of IA can be confined to those systems and areas of the plant listed in 35 above.	Close valve IA214 to isolate the failure to those systems and plant areas listed under 35 above. Maintenance repairs the failed header.
37. Manual valve IA214 fails open and cannot be closed	Gradual buildup of scale, rust, debris or other contamination prevents valve from closing	No effect unless the failure is combined with a second failure such as the IA header failure discussed in 36 above.	No immediate operator action required. Maintenance corrects the problem.
38. Manual valve IA213 fails closed	1. Operator/maintenance error 2. Buildup of rust, scale, debris or other contamination	This failure results in loss of IA to the pneumatic valves and instruments in the following systems and areas of the plant: 1. Turbine deck, east and west 2. Auxiliary boilers 3. Deareator 4. Condenser area ring 5. Sewage treatment 6. Intake core, water pumps 7. Condensate precoat filters 8. Turbine lube oil coolers 9. FW heaters 14A,14B,15A,15B,16A,16B	1. Operations and maintenance personnel attempt to discover and correct the source of the problem. 2. Operator responds as directed by EOP-14, the "Loss of Instrument Air" procedure

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
		10. Auxiliary FW pumps 11. Condenser area west 12. Moisture seperator reheaters 11 & 12	
39. Failure of IA header downstream of manual valve IA213 so that IA pressure decreases below 80psig	Mechanical damage to the 2" header by maintenance personnel or by equipment failure	This failure can result in a total loss of IA transient if not quickly diagnosed. Once the plant staff recognizes and diagnoses this problem, the loss of IA can be confined to those systems and areas of the plant listed in 38 above.	Close valve IA213 to isolate the failure to those systems and plant areas listed under 38 above. Maintenance repairs the failure header.
40. Manual valve IA213 fails open and cannot be closed	Gradual buildup of scale, rust, debris or other contamination prevents valve from closing	No effect unless the failure is combined with a second failure such as the IA header failure discussed in 39 above.	No immediate operator action required. Maintenance corrects the problem.
41. Manual valve IA656 fails closed	1. Operator/maintenance error	This failure results in loss of IA to the pneumatic valves and instruments in the following systems and areas of the plant: 1. Systems inside the containment structure that includes the CVCS, the containment purge system, the RCS, and the safety injection system 2. Auxiliary FW control valves and atmospheric dump valves 3. West piping penetration room	Operator can start salt water air compressors 11 and/or 12 and open manual valve IA727 and/or 726. These actions will allow the salt water compressors to provide air to the IA loads downstream of IA656. 2. Operations/maintenance attempts to correct problem 3. If necessary implement EOP-14, the "Loss of Instrument Air" procedure.

Table C12. (continued)

FAILURE	POSSIBLE CAUSES	EFFECTS	REMEDIAL ACTIONS
42. Failure of IA header downstream of manual valve IA656 so that IA pressure decreases below 80psig	Mechanical damage to the header by maintenance personnel or by equipment failure	This failure can result in a total loss of IA transient if not quickly diagnosed. Once the plant staff recognizes and diagnoses this problem, the loss of IA can be confined to those systems and areas of the plant listed in 41 above.	Close valve IA656 to isolate the failure to those systems and plant areas listed above. Maintenance repairs the failed header.
43. Manual valve IA656 fails open and cannot be closed	Gradual buildup of scale, rust, debris or other contamination prevents valve from closing	No effect unless this failure is combined with a second failure such as the IA header failure discussed above.	No immediate operator action required. Maintenance corrects the problem.
44. Trip of both IA compressors and the PA compressor	1. Failure of all three service water pumps (low probability) 2. Failure closed of SRW pressure control valve 1628 3. Loss of both 500 KV electrical buses	Both IA compressors will overheat and trip off line. Also, the PA compressor will overheat and trip off line. This event is assumed to occur in Unit 1 and the Unit 2 PA compressor normally would be cross connected to the Unit 1 PA system and could serve as a backup source of compressed air. If this is the case, IA pressure should not drop below 85 psig and no adverse plant effects should be experienced.	The operator can take the following actions: 1. Attempt to restore service water flow 2. Use Unit 2 compressors to provide backup compressing capability for Unit 1. 3. Implement EOP-14 "Loss of Instrument Air" if 1 or 2 above is not successful.

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APPENDIX D

APPENDIX D

FAILURE MODES AND EFFECTS ANALYSIS (FMEA) OF THE REGULATING SYSTEMS ELECTRIC POWER DISTRIBUTION CIRCUITRY AT THE CALVERT CLIFFS UNIT 1 NUCLEAR POWER PLANT

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ABSTRACT

The effects of regulating system electric power supply failures have been analyzed for the Calvert Cliffs Unit 1 power plant. Instrument and control system power distribution circuits were analyzed to define a comprehensive set of 24 single-point failure modes. Selected multiple power distribution failures were analyzed for circuits found to significantly affect regulating system response. For each power supply failure, the regulating system outputs were propagated through the energized and deenergized output control devices to determine the initial plant response. In addition, the effects of power supply failures on subsequent plant control were evaluated.

Plant response to regulating system electrical power supply failure was not found to be severe. The regulating systems are substantially decoupled due to operation of the reactor and turbine generator in the manual mode only and the use of separate feedwater regulating systems for each steam generator. Redundant reactor, reactor coolant pressure, and pressurizer level regulating systems are available, but reactor coolant pressure and pressurizer level regulating functions are coupled through non-vital instrument power to control components. Some of the associated transients may initially appear similar to a small-break LOCA or voiding in the reactor coolant system. Steam line safety valves may be challenged by loss of turbine bypass and atmospheric steam dump valve operations. Pressurizer relief valve operation and isolation can be affected. There is a possibility for overfilling one steam generator. These control failures can be managed through operator response and are not felt to have new or significant safety implications.

D1. INTRODUCTION

1.1 SCOPE OF WORK

This report presents the results of a failure modes and effects analysis (FMEA) of the electrical power supplies to the Calvert Cliffs Unit 1 regulating systems. The objectives of this work were as follows:

1. Perform a FMEA of the regulating systems power supplies to identify regulating system failures resulting from single point and selected multiple power supply failures.
2. Evaluate the initial or near-term response of the plant to the failed outputs resulting from each postulated power failure.
3. Note any failures that could lead to substantial imbalance between heat generation and removal or feedwater control problems.
4. Suggest design modifications that might eliminate or reduce the frequency or effects of the postulated power failures.

This study was performed for the U.S. Nuclear Regulatory Commission (NRC) and carried out by Science Applications International Corporation (SAIC) under the direction of Oak Ridge National Laboratory (ORNL). The seven regulating systems addressed in this study are identified in Table D1.

1.2 TECHNICAL APPROACH

The analysis of the regulating systems responses to power supply failures was performed using a modified FMEA. The regulating systems power supplies were identified and failure modes were defined. Regulating system control failures and actions were determined for each power supply single failure mode. Multiple failures were identified that involved additional losses of regulating function. These failures, the initial transient, and subsequent plant control were reviewed for each response.

Table D1. Calvert Cliffs Unit 1 regulating systems

System	Principal Functions
Reactor Regulating System (RRS)	Provide control signals which are used to regulate steam dump on high reactor Tavg after turbine trip, adjust pressurizer level setpoint as a function of power, and indicate high and low reactor Tavg error.
Control Element Drive System (CEDS)	Transmit signal from CEDS control console to the coil power programmers which develop the pulses for magnetic jack operation.
Reactor Coolant Pressure Regulating System	Maintain system pressure within specified limits by the use of pressurizer heaters and spray valves.
Pressurizer Level Regulating System	Regulate pressurizer level as a function of power by comparing measured pressurizer level to a programmed pressurizer level set point from the RRS to control letdown control valve position and start or stop charging pumps.
Feedwater Regulating System	Maintain steam generator downcomer level within acceptable limits by positioning feedwater regulating valves which control the feedwater to each steam generator.
Atmospheric Steam Dump and Turbine Bypass System	Dissipate excess NSSS stored energy and sensible heat following a turbine trip without lifting the safety valves.
Turbine Generator Control System	Control steam flow to the turbine.

1.3 REPORT CONTENTS

This report describes the results of the Calvert Cliffs Unit 1 Regulating Systems FMEA. The conclusions obtained from these results are summarized in Section 2. Brief descriptions of the regulating systems and their electric power distribution circuitry are given in Sections 3 and 4. The results of the power supply FMEA for each power supply failure case are presented and discussed in Sections 5 through 14.

D2. SUMMARY OF RESULTS

A detailed analysis of the effects of regulating system electrical power supply failures has been performed for the Calvert Cliffs Unit 1 nuclear power plant. This analysis consisted of determining the response of the regulating systems output signals to single and selected multiple point failures in the power supply circuitry. From these conditions, the automatic response of the plant and subsequent control were evaluated.

The regulating systems functions were found to be substantially decoupled due to manual control of reactor power, manual control of the turbine generator system, and setpoint control of steam generator level. Electrical power supply failures affect reactor coolant pressure, pressurizer level, main feedwater regulating valve and pump speed control, and atmospheric steam dump and turbine bypass control. These responses are primarily associated with failures of the non-vital instrument buses 1Y09 and 1Y10 and 125-V dc bus 11. Failures of vital instrument buses 1Y01 and 1Y02 can also affect these functions through the reactor, reactor coolant pressure, and pressurizer level regulating systems. Vital instrument bus single failure response can be corrected promptly by selecting the alternate regulating systems for these functions.

The reactor coolant pressure and pressurizer level response to electrical power supply failures can lead to reactor trip in some cases. Pressurizer spray, pressurizer heater control, feedwater regulating valve 11, and feedwater pump speed control will remain failed until instrument bus 1Y09 is restored. Letdown flow control will remain failed until instrument bus 1Y10 is restored. Turbine bypass valves will fail closed until 125-V dc bus 11 is restored. Failure of 125-V dc bus 11 will result in Unit 1 turbine trip and may cause Unit 2 turbine trip. Manual controls are generally available for other regulating system functions following a single power failure.

The dominant reactor coolant pressure and pressurizer level regulating system response is to initiate a transient of decreasing reactor coolant pressure and/or increasing pressurizer level due to the loss of the pressurizer heaters, closure of the letdown control valve, and starting of the backup charging pumps. If unterminated, this could lead to filling the pressurizer and liquid discharge through the pressurizer relief or code safety valves. Changes in reactor coolant pressure and pressurizer level could initially be interpreted as a small break LOCA or voiding in the reactor coolant system. Operator identification of the power supply failure will contribute to the interpretation of this response.

The failure of instrument bus 1Y09 will freeze the steam generator 11 main feedwater regulating valve and the main feedwater pump speed as-is. This will lead to constant feedwater flow to this steam generator. The main feedwater pump speed will also not run back on auxiliary feedwater actuation for this bus failure. The feedwater pumps can be manually tripped at the pump turbine to terminate this flow.

Failure of dc bus 11 will inhibit automatic operation of the pressurizer relief valves. This failure will lead to turbine trip and reactor trip with the result that the pressurizer code safety valves will be challenged. Failure of MCC 104R or MCC 114R may lead to a reactor trip through effects on non-vital instrument bus 1Y10 or 1Y09, respectively, and will fail one pressurizer relief isolation valve as-is. If the pressurizer relief valve sticks open during the transient, it cannot be isolated until the associated block valve motor control center is restored.

A double vital bus failure for 1Y01 and 1Y02 would initiate a reactor trip, open the pressurizer relief valves, deenergize the pressurizer heaters, and inhibit automatic control of pressurizer level. The pressurizer spray, charging pumps, and letdown throttle valve could be controlled manually. Double failures of instrument buses 1Y09 and 1Y10 and combinations of 1Y01 and 1Y02 with 1Y09 and 1Y10 failures generally produce the same regulating system response as single failures of 1Y09 or 1Y10 with some additional loss of steam generator instrumentation.

Much of the single failure response could be eliminated by providing automatic bus transfers betwen 1Y09 and 1Y10 for non-vital powered components in the reactor coolant pressure regulating system, the pressurizer level regulating system, the main feedwater regulating valve solenoids, and the main feedwater pump speed control.

In summary, failures of the regulating system power supplies can lead to reactor trips and increased dependence on code safety valves for secondary pressure control. They may also lead to constant feedwater supply to one steam generator. The major effects could be reduced by developing alternate power supplies for the pressurizer heater and charging pump regulating interface relays and the pressurizer spray and letdown control valve regulating interface modules. The design philosophy for failing the main feedwater valves as-is on loss of instrument power should be reviewed.

The control failures and regulating systems responses to these failures can be managed by operator actions and should not significantly affect core cooling or the ability to achieve cold shutdown.

D3. REGULATING SYSTEMS FUNCTIONAL DESCRIPTIONS

Seven regulating systems provide the signal processing and control functions required for operation of the Calvert Cliffs Unit 1 nuclear steam supply system. These systems provide information and controls for reactor regulation, control element drive position, reactor coolant pressure, pressurizer level, main feedwater flow to the steam generators, atmospheric steam dump and turbine bypass valves, and steam flow to the high pressure turbine. Summary descriptions and functional block diagrams for these systems are provided below. More detailed descriptions of the functions performed by the regulating systems may be found in Reference 1. The regulating systems are primarily implemented with current loops for noise and signal isolation. The block diagrams are shown as functional equivalents in a voltage mode format for simplified illustration and are based on drawings provided by Baltimore Gas and Electric Company (Reference 2).

3.1 REACTOR REGULATING SYSTEM

The reactor regulating system, illustrated in the functional block diagram in Figure D1, is used to provide signals for:

- Atmospheric steam dump area demand,
- Atmospheric steam dump quick-open permissive,
- Pressurizer level setpoint, and
- High and low alarm indication of the differences between reactor Tavg and the computed Tref.

The operator can select one of two reactor regulating systems designed as X or Y with a manual selector switch. Each system is separate and independent of the other and receives ac power from separate vital 120-V ac instrument buses. Reactor regulating system inputs and outputs are listed in Table D2.

The controlling reactor Tavg signal is developed by passive summation of current signals from selected temperature sensors. This signal is operated on by a function generator to provide an analog output for atmospheric steam dump and turbine bypass valve area demand and quick open. As Tavg increases, the

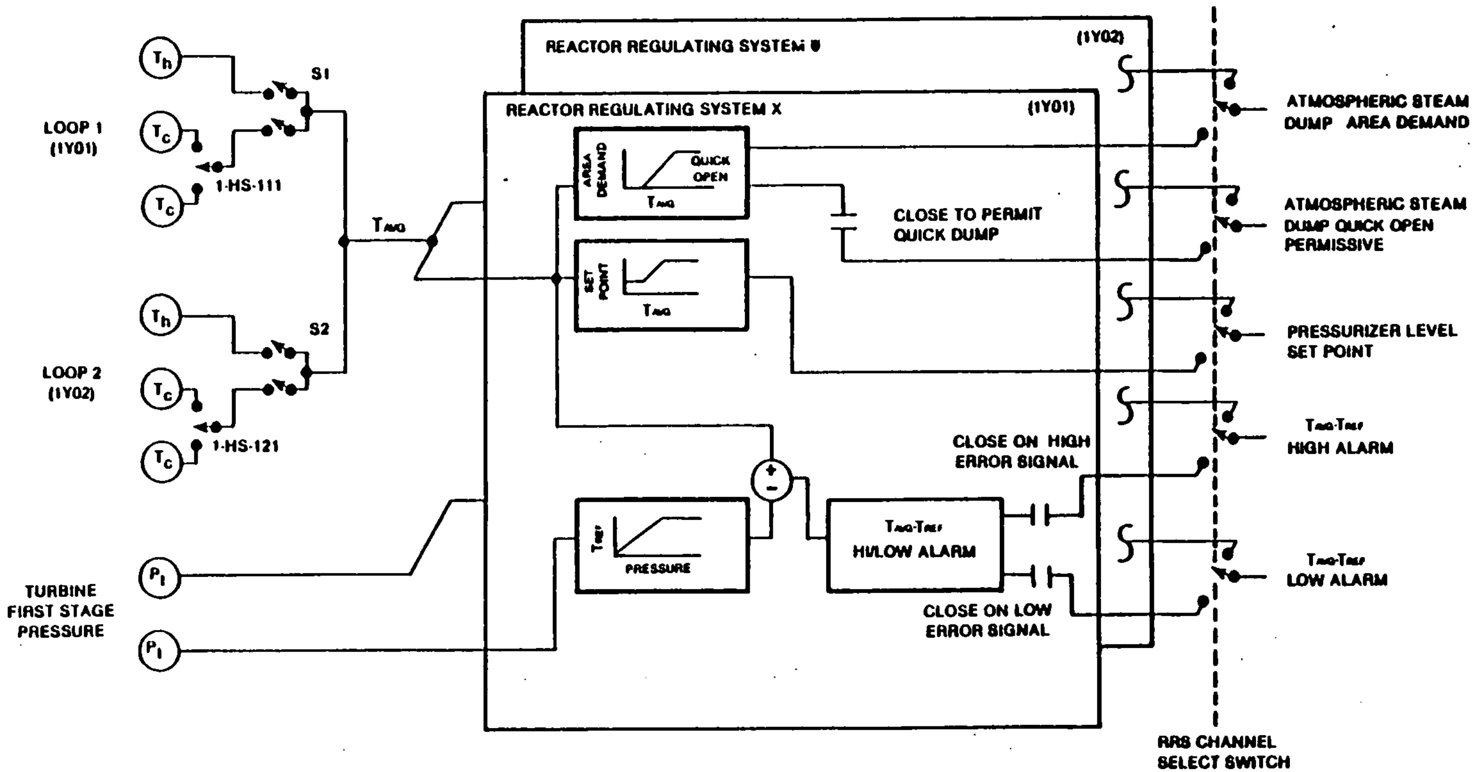


Fig. D1. Reactor regulating system functional block diagram.

Table D2. Reactor regulating system inputs and outputs

Item	Description		Comments
Inputs			
1	1-TIA-111X	Loop 1 T hot	Temperature sensors are manually selected to compute analog Tavg signal for both reactor regulating systems
2	1-TIC-111Y	Loop 1 T cold	Temperature sensors are manually selected to compute analog Tavg signal for both reactor regulating systems
3	1-TIC-115	Loop 1 T cold	Temperature sensors are manually selected to compute analog Tavg signal for both reactor regulating systems
4	1-TIA-121X	Loop 2 T hot	Temperature sensors are manually selected to compute analog Tavg signal for both reactor regulating systems
5	1-TIC-121Y	Loop 2 T cold	Temperature sensors are manually selected to compute analog Tavg signal for both reactor regulating systems
6	1-TIC-125	Loop 2 T cold	Temperature sensors are manually selected to compute analog Tavg signal for both reactor regulating systems
7	PI-3957	Turbine 1st Stage Pressure	To RRS X for Tref calculation
8	PI-4040	Turbine 1st Stage Pressure	To RRS Y for Tref calculation
Outputs			
1	Atmospheric Steam Dump Area Demand		Analog signal to modulate atmospheric steam dump and turbine bypass valves as a function of reactor Tavg

Table D2. (continued)

Item	Description	Comments
2	Atmospheric Steam Dump Quick Open Permissive	Contact closure will permit turbine bypass and atmospheric steam dump quick open after turbine trip
3	Pressurizer Level Setpoint	Analog signal to pressurizer level regulating system adjusts level control setpoint as function of reactor Tavg
4	Tavg - Tref High Alarm	Contact closure indicates high Tavg compared to Tref
5	Tavg - Tref Low Alarm	Contact closure indicates low Tavg compared to Tref

signal to the atmospheric steam dump control valve increases. If the reactor power (as determined by Tavg) exceeds a predetermined power level, the atmospheric steam dump quick open override bistable results in a quick opening of the atmospheric steam dump and turbine bypass valves following a turbine trip.

The Tavg signal is also used to provide a programmed pressurizer level setpoint that increases the pressurizer level as Tavg increases. This programmed setpoint minimizes changes in reactor coolant system water inventory during plant load changes and transients.

A Tavg error signal is developed by comparison of Tavg to the desired reactor coolant average temperature (Tref) that represents a generated power reference signal derived from the first stage turbine pressure. If the difference between Tavg and Tref should become either too high or too low, alarms will annunciate. These alarms indicate an imbalance between reactor power and turbine load.

Loss of power to the selected reactor regulating system will result in a zero atmospheric steam dump area demand, loss of the atmospheric steam dump quick open permissive, regulation of pressurizer level at 270 inches, and loss of the Tavg high and low error alarm.

The reactor regulating system does not actively control the reactor power. The reactor is operated with all control rods fully withdrawn and nuclear power is controlled manually by the operator through reactor coolant boron concentration. The reactor regulating system provides operator guidance in matching the reactor power to generator power through the Tavg high and low alarm. If the Tavg error exceeds the control band, the operator may reduce the error by adjusting boron concentration or adjusting the turbine throttle valve position.

3.2 CONTROL ELEMENT DRIVE SYSTEM (CEDS)

The control element drive system is used to position the reactivity control rods in the reactor core. This system is operated in the manual mode only.

The control rods are fully withdrawn from the core during operation and the reactor power is adjusted through the amount of dissolved boron in the reactor coolant. As a result, the CEDS cannot initiate positive reactivity changes. Faults with the CEDS can result in control rod insertions and reactor trip.

Due to operation of the CEDS in the manual mode with all control rods fully withdrawn and reactor trip functions provided by the reactor protection system, the CEDS is not considered to have a significant involvement in regulating systems interactions.

3.3 REACTOR COOLANT PRESSURE REGULATING SYSTEM

The reactor coolant pressure regulating system controls reactor coolant pressure through automatic control inputs to the pressurizer heaters to produce steam (1500 kW total capacity) and the pressurizer spray flow control valve to condense steam (375 gpm maximum flow). A small continuous flow (1.5 gpm) is maintained through the spray lines at all times to keep the spray lines and the purge line warm, reducing thermal shock during plant transients. The reactor coolant pressure is compared to a setpoint value (2250 psia) and the error signal provides proportional control of the spray valve position and proportional heater element power. Approximately 20% of the heaters are connected to proportional controllers which adjust the heat input as required to account for steady losses and to maintain the desired reactor coolant pressure. The remaining backup heaters are normally off but are turned on by a low reactor coolant pressure signal or high pressurizer level error signal through bistable controller outputs.

Two separate and redundant reactor coolant pressure regulating systems are used to develop the pressure control signals. These systems are powered from separate vital instrument buses and the operator can select either system for reactor coolant pressure control through a manual selector switch. The pressurizer spray valve control signal is further processed through modules involving instrument power. The pressurizer heater demand is also processed through relays powered from instrument power. The pressurizer heater ac power is obtained through 480-V motor control centers (MCCs).

The pressurizer heater controls include relays in the pressurizer level regulating system. These relays act to turn all heaters full on at high pressurizer level and to de-energize all heaters on lo-lo pressurizer level (101 inches). These functions involve the pressurizer level regulating system power supplies in pressurizer heater control.

The reactor coolant pressure regulating system inputs and outputs are summarized in Table D3. A functional block diagram of the reactor coolant pressure regulating system is shown in Figure D2. Backup heater control details are shown in Figure D3.

Loss of vital instrument power to the selected reactor coolant pressure regulating system will produce a zero current demand signal to the pressurizer spray valve and to the proportional heaters. The pressurizer spray valve and backup heaters can be controlled manually through non-vital instrument power.

Loss of non-vital instrument bus 1Y09 will produce a zero current demand signal to the spray valve I/P and fail the backup heater control relay in the "off" position.

While not formally a part of the reactor coolant pressure regulating system, the pressurizer relief valves contribute to reactor coolant pressure control under certain conditions. A two out of four logic indicating high reactor coolant pressure from the reactor protection system will open the two pressurizer relief valves when the reactor coolant pressure exceeds 2385 psig. These valves are sized to be able to release sufficient pressurizer steam during abnormal operating occurrences to prevent opening of the reactor coolant system safety valves. A motor-actuated isolation valve is provided upstream of each of the PRVs to permit isolating the valve. A functional block diagram for pressurizer relief valve control and isolation is shown in Figure D4.

Failure of either the 480-V ac or the 125-V dc buses will result in the PRV's closing or remaining closed. Due to the 2 of 4 logic, failure of any one of the four 120-V ac vital buses supplying the RPS will neither open the PRV nor prevent them from being opened due to high pressurizer pressure. Failure of

Table D3. Reactor coolant pressure regulating system inputs and outputs

Item	Description		Comments
Inputs			
1	PT 100X	Reactor Coolant Pressure	Control signal to pressure regulating system X
2	PT 100Y	Reactor Coolant Pressure	Control signal to pressure regulating system Y
Outputs			
1	Proportional Heater Demand		Analog signal - Function intercepted by high and low level relays in pressurizer level system
2	63X/PC-100	Backup Heater Demand	Relay contacts switch heaters on/off - intercepted by high and lo-lo level relays in pressurizer level system
3	Pressurizer Spray Valve Position		Analog signal to selected spray valve I/P converter

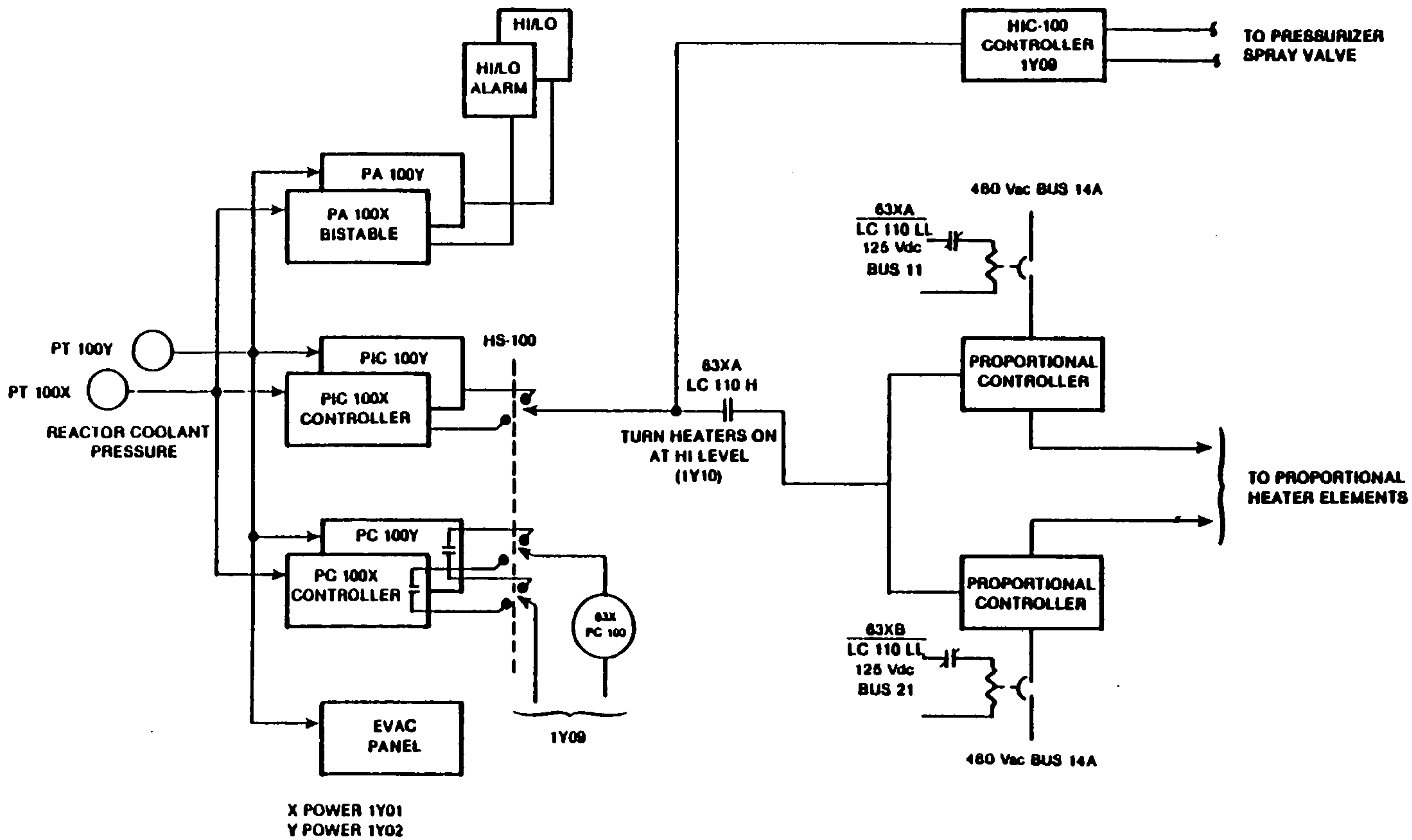


Fig. D2. Reactor coolant pressure regulating system functional block diagram.

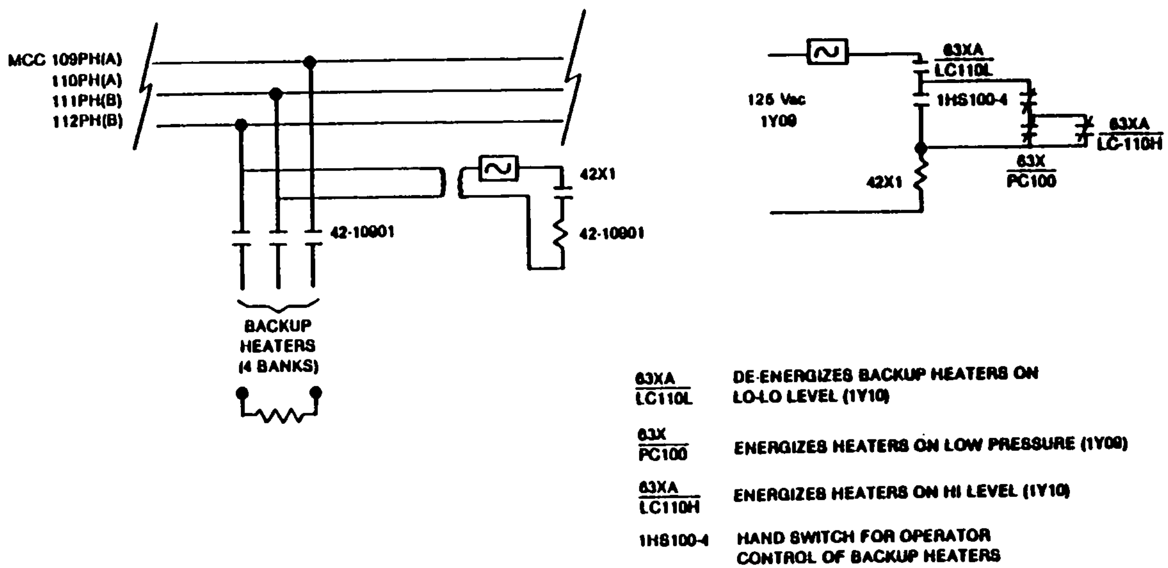


Fig. D3. Back-up heater control functional block diagram.

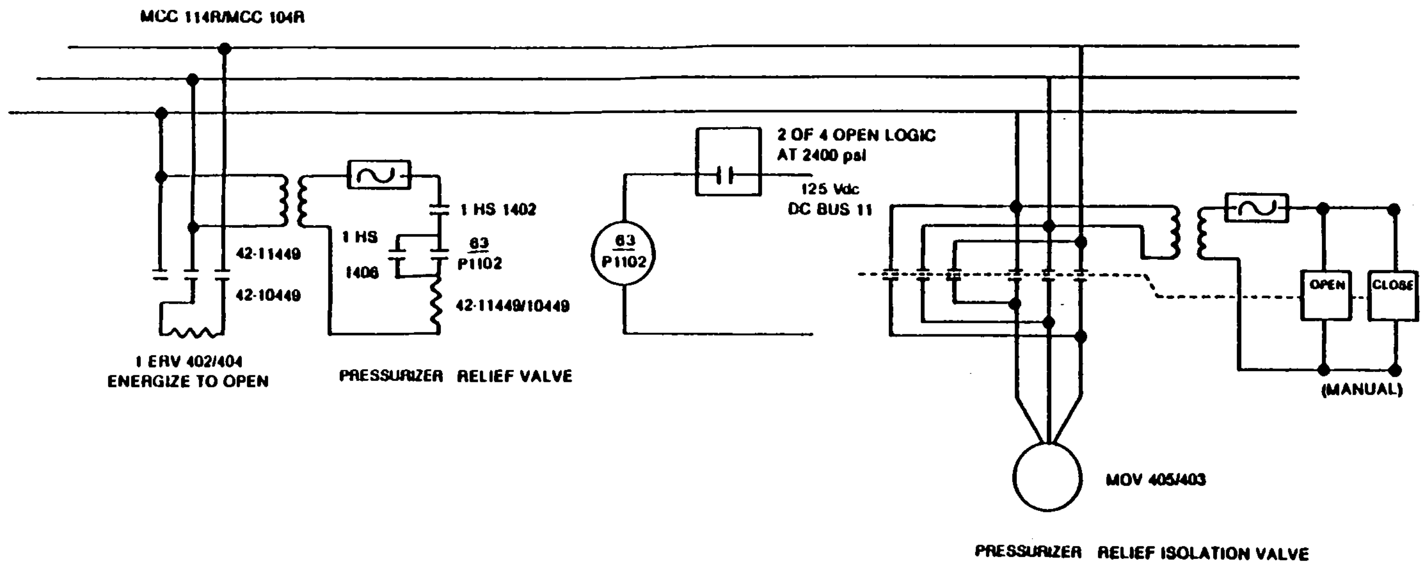


Fig. D4. Pressurizer relief valve control functional block diagram.

any two vital buses, however, will result in both PRV's opening and remaining open until manually closed from the control room or one or both vital buses are reenergized.

3.4 PRESSURIZER LEVEL REGULATING SYSTEM

The pressurizer level regulating system provides automatic control of the pressurizer level through analog control of the letdown control valve position and start/stop control of the backup charging pumps. There are two letdown control valves in parallel lines, each of which can supply a maximum of 128 gpm of letdown flow. Under normal operating conditions, one valve is operating while the other is kept in a standby (closed) condition. Under normal conditions one charging pump is operating at a design flow rate of 44 gpm. On/off control of the backup charging pumps provides an additional 44 gpm per pump for a maximum of 132 gpm. There is no mechanism for throttling the flow on a charging line, i.e., the pump is either on and supplying 44 gpm or off and supplying no flow. When all three pumps are on, flow will be supplied to the primary system up to a pressure which is high enough to lift the pressurizer PRVs (2385 psig). The pressurizer level regulating system also has dominant control over the pressurizer heaters to turn all heaters full on on high pressurizer level and to turn all heaters off on lo-lo pressurizer level.

The pressurizer level control signals are developed in two separate and fully redundant regulating systems. These systems have separate pressurizer level input signals and share the pressurizer level setpoint signal developed in the reactor regulating system. The analog output signal to the letdown control valve and relays used to control the charging pumps and pressurizer heaters operate from non-vital instrument power and are not redundant.

Failure of vital instrument power to the selected pressurizer level regulating system will produce a zero current demand signal to the letdown control valve and to the backup charging pump control bistables. Pressurizer level regulating system bistable outputs will de-energize all pressurizer heaters and stop all but one charging pump. These failures can be corrected by manually selecting the alternate pressurizer level regulating system.

Loss of non-vital instrument bus 1Y10 will provide a zero current demand to the letdown control valve and will de-energize control relays to de-energize all pressurizer heaters and stop all but one charging pump. Pressurizer heater controls will fail off and the letdown control valve will fail closed. The charging pumps can be controlled manually through hand stations.

The inputs and outputs of the pressurizer level regulating system are listed in Table D4. A functional block diagram of the pressurizer level regulating system is shown in Figure D5. Supplemental details of the charging pump motor control are shown in Figure D6.

3.5 FEEDWATER REGULATING SYSTEMS

There are two fully separate feedwater regulating systems. Each system controls the main feedwater regulating valve and bypass valve position for one steam generator. Each steam generator level signal is compared to a setpoint and corrected by the ratio of steam flow to feedwater flow to provide the corresponding feedwater regulating valve position control. The main feedwater regulating valves are automatically closed and the bypass valves set to 5% of full power feedwater flow following reactor trip. This valve position can be manually overridden by the operator.

The two feedwater regulating systems receive primary ac power from separate vital buses. On the failure of a vital bus, the feedwater regulating system without power automatically transfers to a separate non-vital instrument bus to restore power for continued plant operation. It therefore requires one vital and one non-vital instrument bus failure to lose one feedwater regulating system, and two vital and two non-vital instrument bus failures to lose both feedwater regulating systems.

Inputs and outputs of the feedwater regulating systems are summarized in Table D5. A functional block diagram of the feedwater regulating systems is shown in Figure D7.

The main feedwater regulating valve electro-to-pneumatic (E/P) position controllers have solenoid valves on the air lines that use non-vital

Table D4. Pressurizer level regulating system inputs and outputs

Item	Description		Comments
Inputs			
1	LC110X	Pressurizer Level	
2	LC110Y	Pressurizer Level	
3	Pressurizer Level Setpoint		From reactor regulating system
Outputs			
1	63X CH11	Relay	Start/stop charging pump 11[1]
2	63X CH12	Relay	Start/stop charging pump 12[1]
3	63X CH13 and 63X CH14	Relays	Start/stop charging pump 13[1]
4	63XA/LC110L	Relay	De-energizes to turn off all backup heaters on lo-lo level. Loss of control power to this relay overrides all control of backup heaters and de-energizes Group A proportional heaters.
5	63XB/LC110L	Relay	De-energizes to turn off Group B proportional heaters on lo-lo level
6	63XA/LC110H	Relay	De-energizes to turn heaters on at high level
7	63XB/LC110H	Relay	De-energizes to stop all but one charging pump on high level

[1]One charging pump is normally operating. Control relays de-energize to start one selected out of the remaining two charging pumps.

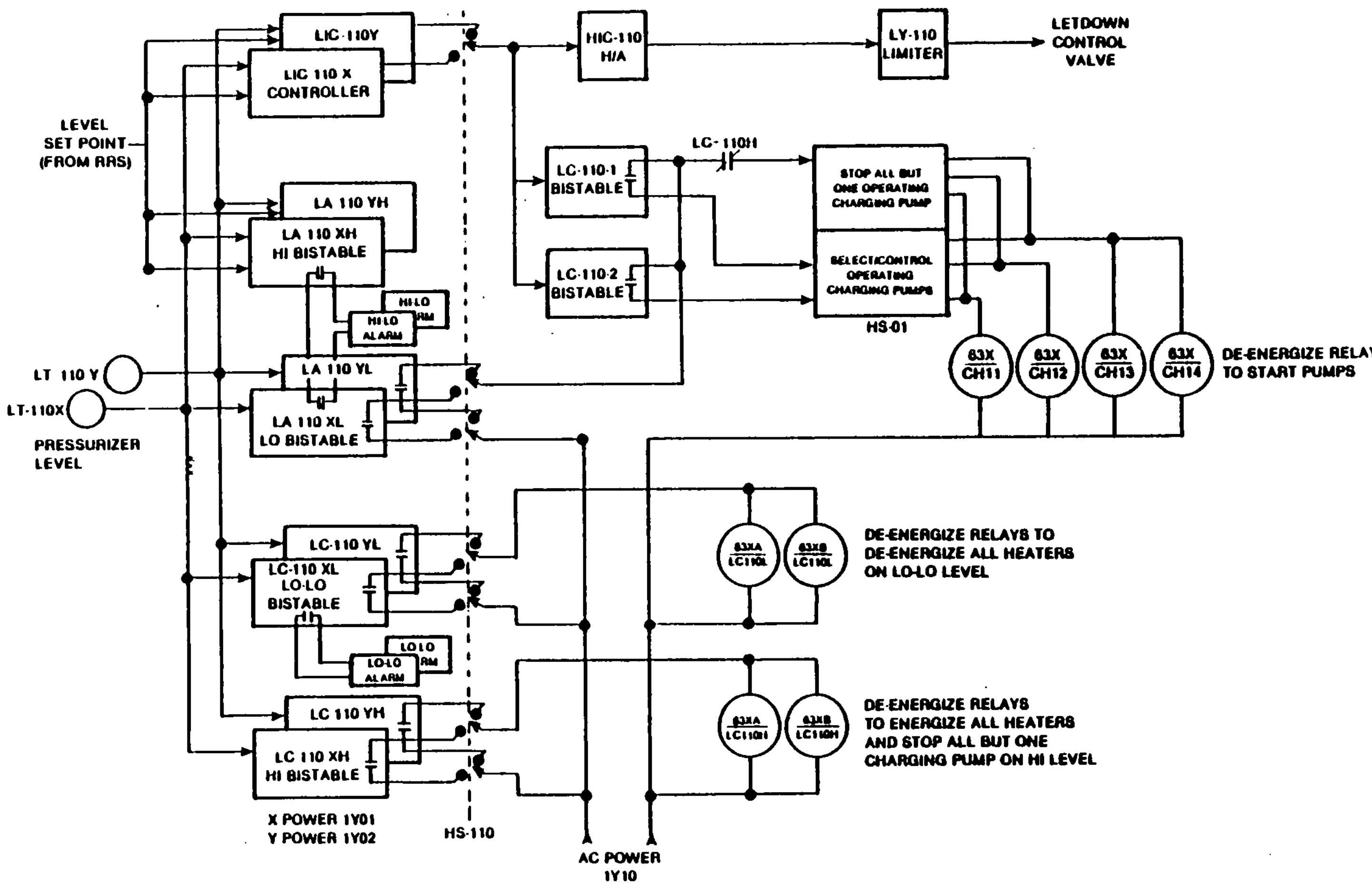
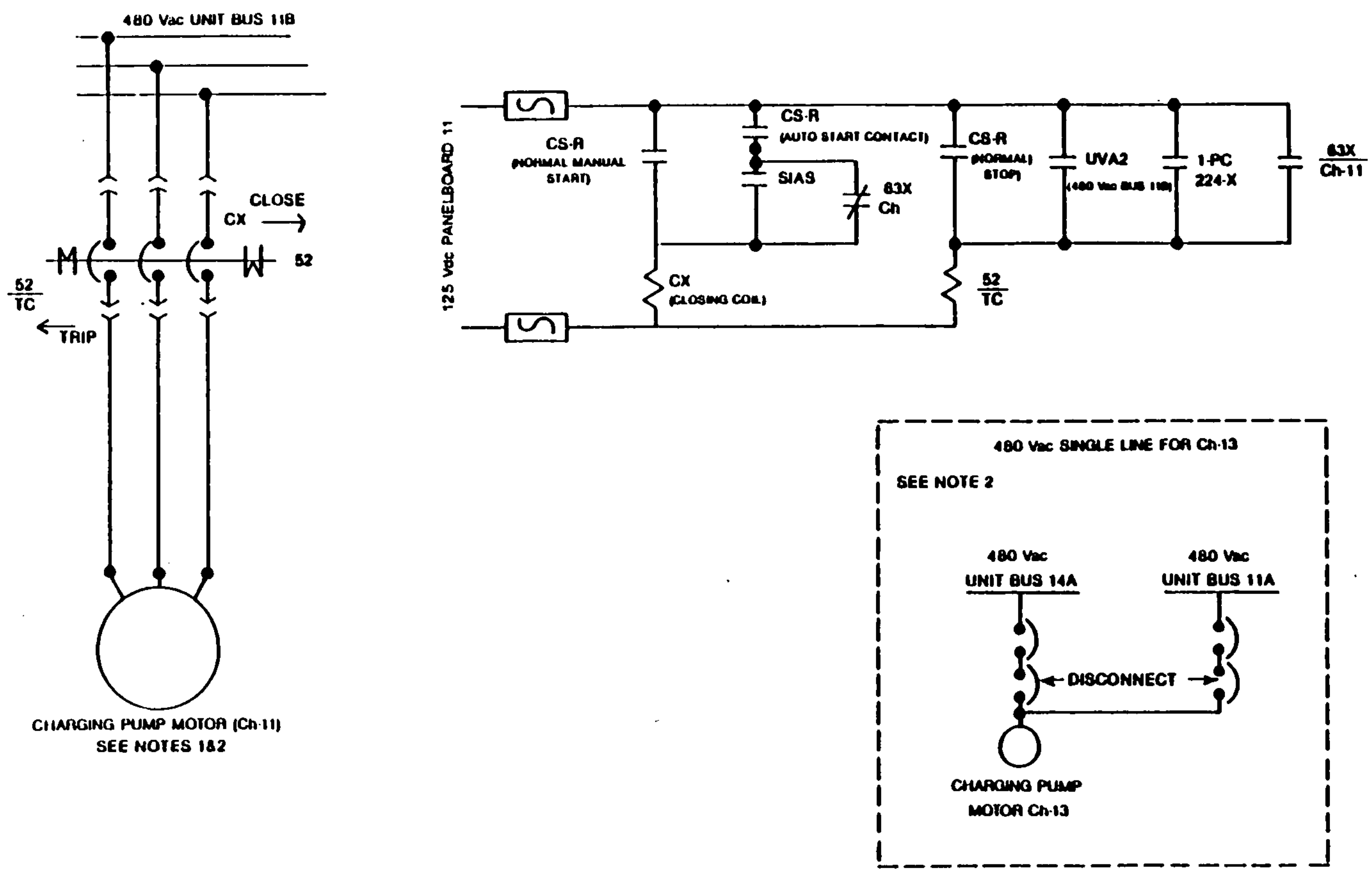


Fig. D5. Pressurizer level regulating system functional block diagram.



NOTE 1. CHARGING PUMP MOTOR (Ch-12) FED FROM 480 Vac BUS 14B, dc PANELBOARD 21
NOTE 2 CHARGING PUMP MOTOR (Ch-13) FED FROM 480 Vac BUS 14A OR 480 Vac BUS 11A VIA MANUAL SWITCH; dc PANELBOARD 11 OR 21

Fig. D6. Charging pump motor control functional block diagram.

Table D5. Feedwater regulating system inputs and outputs

Item	Description		Comments
Inputs			
1	1-FT-1011/ 1-FT-1012	Steam Flow	Analog signal to regulating system 11/12
2	1-FT-1111/ 1-FT-1112	Feedwater Flow	Analog signal to regulating system 11/12
3	1-LT-1111/ 1-LT-1112	Downcomer Level Transmitter	Normally for main FW regulating valve control in regulating system 11/12
4	1-LT-1105/ 1-LT-1106		Normally for bypass FW valve control in regulating system 11/12
Outputs			
1	1-FLV-1111/ 1-FLV-1112	Main Feedwater Regulating Valve E/P	Analog valve position signal for steam generator 11/12
2	1-HCV-1105/ 1-HCV-1106	Bypass Valve E/P	Analog valve position signal for steam generator 11/12

NOTE: Each steam generator has a separate feedwater regulating system. The input and output tag numbers shown correspond to SG11 followed by SG12.

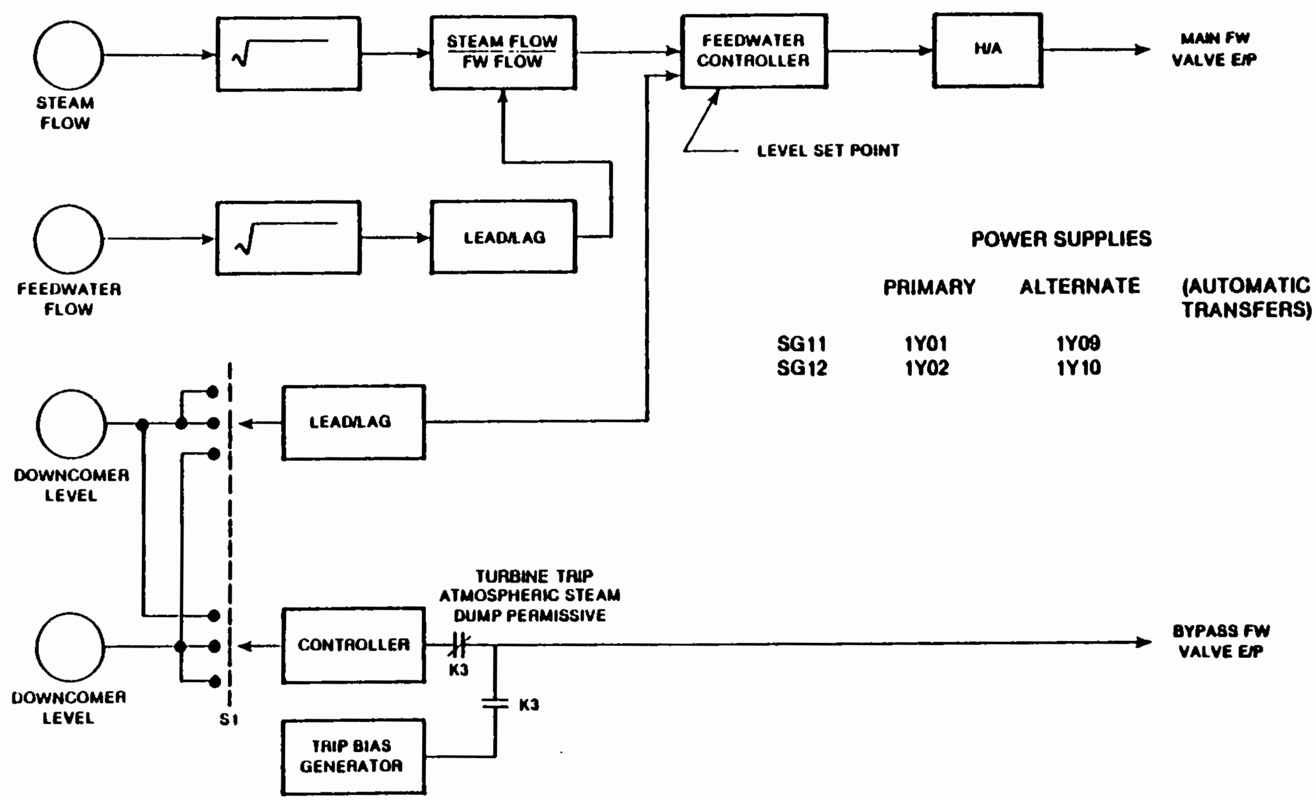


Fig. D7. Feedwater regulating system functional block diagram.

instrument power. Each of the two main feedwater regulating valves has a different source of instrument power. Loss of non-vital instrument bus 1Y09 or 1Y10 will fail the affected main feedwater regulating valve position as-is.

While not a part of the feedwater regulating system, the main feedwater pump speed control participates in feedwater flow control. This function controls the main feedwater pump turbine speed to maintain a constant pressure drop across the main feedwater regulating valves. The main feedwater pump speed control uses non-vital instrument bus 1Y09. Loss of this power results in the failure of main feedwater pump speed control at the operating value. The main feedwater pumps can be tripped manually at the pump following this loss of power. The main feedwater pump speed control inputs and outputs are summarized in Table D6. A functional block diagram of the main feedwater pump speed control is shown in Figure D8.

3.6 ATMOSPHERIC STEAM DUMP AND TURBINE BYPASS SYSTEM

The atmospheric steam dump and turbine bypass system provides for steam pressure control through the two atmospheric steam dump valves which exhaust to the atmosphere and the four turbine bypass valves which exhaust downstream of the MSIVs to the main condenser. The steam flow capacity of each turbine bypass valve is 10%, making the total capacity of the turbine bypass system 40% of full power steam flow. Each atmospheric steam dump valve can relieve 2.5% of full power steam flow.

Prior to turbine roll, or under conditions where steam pressure exceeds a set value, steam generator outlet pressure is used to regulate turbine bypass valve position. Following a turbine trip, the larger of the secondary steam generator outlet pressure error or Tavg error from the reactor regulating system is selected to modulate turbine bypass valve position. The Tavg error is also used to control atmospheric steam dump valve area following a reactor trip. If the Tavg error is greater than a setpoint value, then both the turbine bypass valves and atmospheric steam dump valves receive a quick open signal following turbine trip. The valve position control will return to area demand based on steam pressure and/or Tavg error when the Tavg error is below the quick open setpoint. Loss of condenser vacuum will result in a quick

Table D6. Main feedwater pump speed control inputs and outputs

Item	Description		Comments[1]
Inputs			
1	1-PDT-4516	DP Transmitter	Main FW regulating valve 1-CV1111-DP
2	1-PDT-4517	DP Transmitter	Main FW regulating valve 1-CV1121-DP
Outputs			
1	FW Turbine 11	Speed Demand	Analog signal to motor control unit
2	FW Turbine 12	Speed Demand	Analog signal to motor control unit

[1]AFAS actuation without steam generator tube rupture logic actuation will run pump speed back to minimum recirculation.

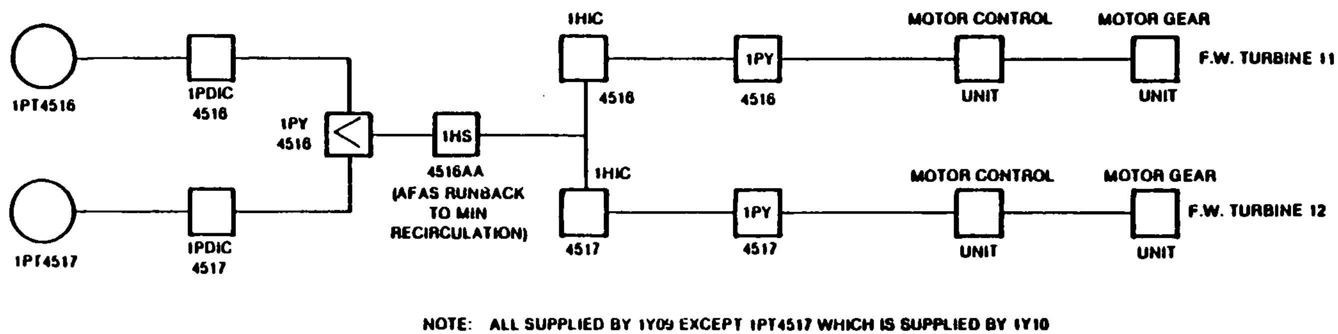


Fig. D8. Feedwater pump speed control functional block diagram.

close signal to the turbine bypass valves. The quick close signal dominates all other control inputs to the turbine bypass valves.

Loss of dc bus 11 will close or hold closed the turbine bypass valves due to the quick close action of isolation solenoid valves. The atmospheric steam dump valves will not quick open without power from dc bus 11; however, manual control is available for these valves. Instrument power for turbine bypass valve pressure control or the atmospheric steam dump valve Tavg error regulating or hand control stations was not identified from the available documentation. Loss of this power will act to close the affected valves.

The turbine bypass and atmospheric dump system inputs and outputs are summarized in Table D7. The system functional block diagram is shown in Figure D9.

3.7 TURBINE GENERATOR CONTROL

The turbine generator system is controlled manually. During load changes, operators adjust the position of the four turbine main steam control valves in coordination with reactor power changes to maintain the reactor Tavg error within programmed limits. These limits are indicated by the reactor regulating system through the comparison of the reactor Tavg to a computed Tref derived from the turbine first stage pressure. Since the turbine first stage pressure varies as a function of turbine load, these actions provide a match between reactor thermal power and generated electric output.

While some station power supply failures can cause a turbine trip, closure of the turbine control valves does not affect the ability of other regulating systems to operate as designed. As a result, the turbine generator control system is not considered to have a significant interaction with other regulating systems.

Table D7. Atmospheric steam dump and turbine bypass system inputs and outputs

Item	Description	Comments
Inputs		
1	1-PT-4056 Steam Generator Outlet Pressure	Analog signal for atmospheric steam dump and turbine bypass valve area control
2	Tavg from Reactor Regulating System	Analog signal for atmospheric steam dump and turbine bypass valve area control
3	Turbine Trip Status	Closed contact indicates turbine trip
4	Condenser Vacuum	Open contact indicates loss of vacuum
5	Relay contact K7 from reactor regulating system	Closed contact indicates quick open permissive
Outputs		
1	Turbine Bypass Valves (4)	Analog position signal
2	Atmospheric Steam Dump Valves (2)	Analog position signal

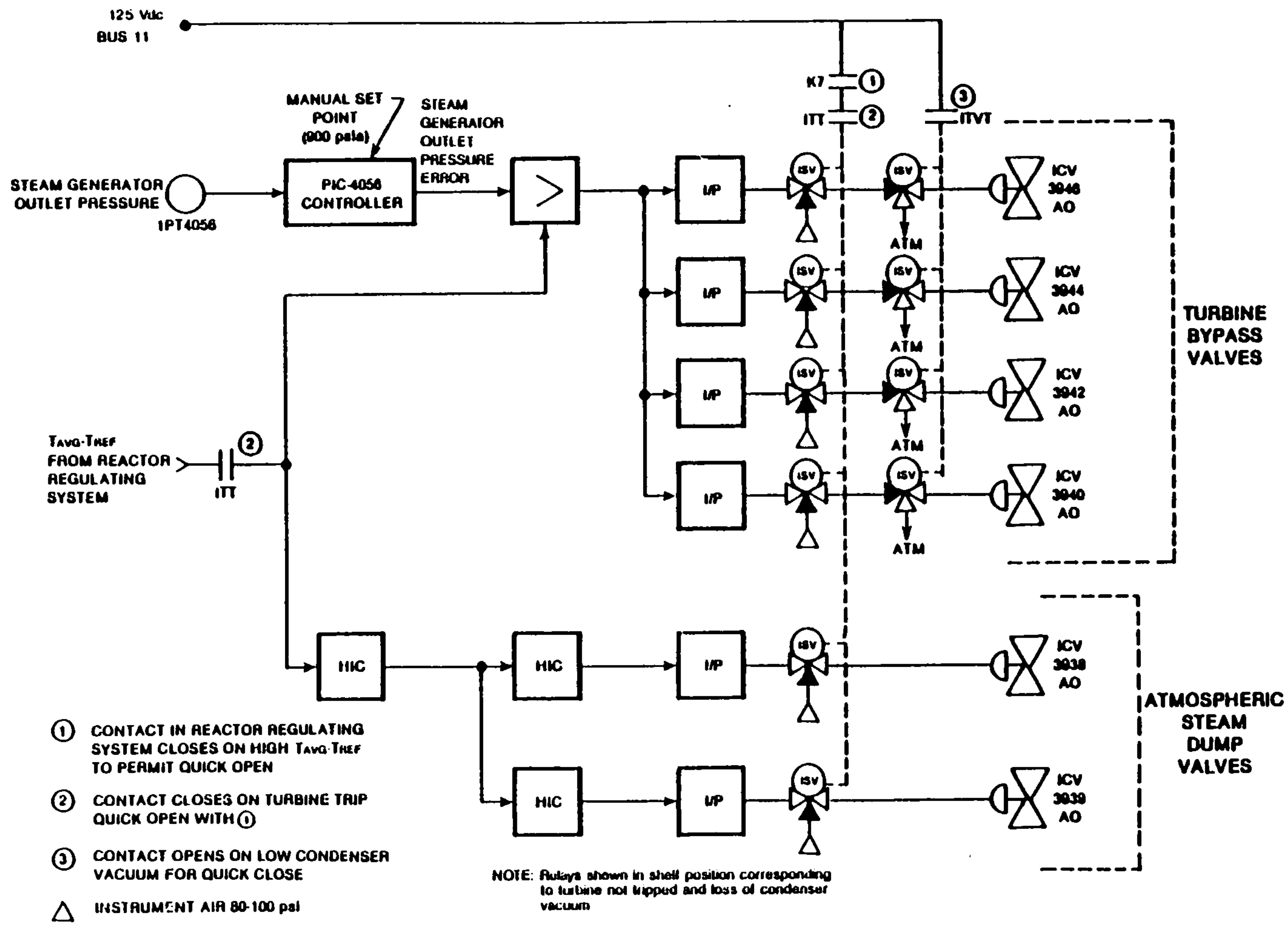


Fig. D9. Turbine bypass and atmospheric steam dump functional block diagram.

D4. POWER SUPPLY DEFINITION AND ANALYSIS

The Calvert Cliffs Unit 1 ac electric power distribution is shown in a simplified schematic diagram in Figure D10. The plant power requirements normally are supplied from the switchyard through 13-kV service buses 11, 12, and 21. Bus 12 supplies the four reactor coolant pump buses, and bus 11 supplies the 4-kV unit buses 11, 12, 13, 15, and 16. Bus 21 supplies 4-kV unit bus 4.

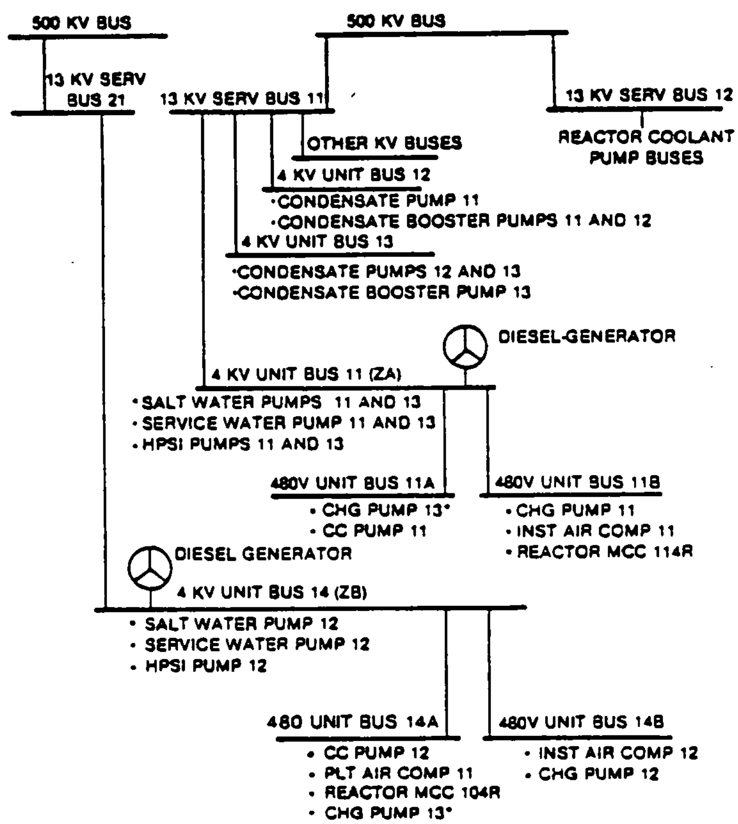
The safety related Channel ZA and ZB power requirements are supplied by 4-kV unit buses 11 and 14, respectively. These buses are energized by two of the three emergency diesel generators shared by the two Calvert Cliffs units.

The 4-kV unit buses supply the 480-V unit buses through transformers. In particular, 4-kV unit bus 11 supplies 480-V buses 11A and 11B; 480-V unit bus 11B supplies 480-V reactor MCC 114R. The 4-kV unit bus 14 supplies 480-V unit buses 14A ad 14B, and 480-V unit bus 14A supplies 480-V reactor MCC 104R.

Plant dc loads are supplied by 125-V dc buses 11, 12, 21, and 22, and 250-V dc bus 13 which are shared between the two units. Each dc bus normally is fed by its associated battery charger (i.e., bus 11 fed by battery 11 and battery charger 11). The four 125-V dc battery chargers 11, 12, 21, and 22 are fed by 480-V unit buses 11A, 14B, 21B, and 24A respectively.

The 120-V ac instrument buses are fed from the dc buses through inverters or from the 480-V ac MCC's through transformers. The 120-V ac vital buses 11, 12, 13, and 14 are supported through their associated inverters from dc buses 11, 21, 12, and 22 respectively. The vital buses may also be fed, by manual transfer, from 120-V ac bus 1Y11. The 120-V ac buses 1Y10 and 1Y11 are fed through their transformers from 480-V ac MCC 104R. Bus 1Y09 is fed from MCC 114R.

Electric bus failures can occur for a variety of reasons including isolation or failure of feeder buses or shorts that could occur during maintenance. For purposes of this analysis, single unspecified failures have been postulated at various points in the power distribution circuitry. The failure has been



* CHARGING PUMP 13 FED BY 480-V UNIT BUSES 11A OR 14A VIA MANUAL SWITCH

Fig. D10. Simplified schematic of Calvert Cliffs Unit 1 ac power distribution.

assumed to de-energize the directly affected bus, buses fed only from this bus, and possibly the feeder buses to the affected bus. In cases where a maintenance tie exists, failures affecting both normally iolated buses were considered.

The 4-kV unit buses shown on Figure D10 have multiple sources of power (13-kV service bus 11 and the emergency diesel-generators). Thus, 4-kV unit bus failures were assumed due to postulated faults on the 4-kV unit buses. This fault results in de-energizing the lower voltage bus fed from the affected bus. Similar faults were postulated on lower voltage buses. Maintenance ties between MCCs 104R and 114R and between non-vital instrument buses 1Y09 and 1Y10 were considered possible mechanisms for propagating a single fault to both of these MCCs or the non-vital instrument buses.

The 125-V dc buses 11, 12, 21, and 22 each have multiple independent power supplies and have no maintenance ties. Therefore, only faults affecting single buses were considered.

Each of the 120-V ac vital buses (1Y01, 1Y02, 1Y03, and 1Y04) is normally fed from a separate dc bus through an inverter. One or more vital buses may be fed from 120-V ac bus 1Y11. Therefore, single and multiple vital bus failures were considered.

Where either of two instrument buses supply a single instrument panel by automatic selection, two failure modes were considered. A fault in the panel could result in both feeder buses being isolated from the panel. The feeder buses would continue to supply other loads in this case. The analysis also considered the possibility of a panel fault propagating to the primary supply bus and subsequently propagating to the backup supply bus on automatic transfer. In this case, the two buses feeding the panel would be deenergized.

The Calvert Cliffs Unit 1 regulating system power supplies were identified and located on the station one-line power distribution. Single failures were postulated at each node in the power distribution system and the affected regulating systems and functions were identified. Multiple failures were postulated for buses involving maintenance ties and regulating system loads.

Power supply failures which did not affect regulating systems functions were removed from consideration. Twenty-four distinct single point bus failures were identified that affect the regulating systems. These failure points, associated lower level buses, and the affected regulating system functions are summarized in Table D8. The multiple instrument bus failures that were analyzed are summarized in Table D9.

Table D8. Calvert Cliffs Unit 1 regulating systems power supply failure modes

Item	Bus Failure Point	Lower Level Bus Failures	Affected Control Functions
1	1Y01	None	Reactor, reactor coolant pressure, and pressurizer level systems (if selected to this bus)
2	1Y02	None	Reactor, reactor coolant pressure, and pressurizer level systems (if selected to this bus)
3	1Y09	None	Pressurizer spray, pressurizer backup heaters, one main feedwater regulating valve, main feedwater pump speed
4	1Y10	None	Charging pumps, pressurizer heaters, letdown control valve, one main feedwater regulating valve
5	125-V dc Bus 11	None	Pressurizer relief valves, turbine bypass valves, atmospheric steam dump valves, charging pump 11, half of the proportional heaters, main turbine EHC
6	125-V dc Bus 21	None	Half of the proportional heaters, charging pump 12
7	MCC 109PH	None	1/4 of backup heaters
8	MCC 110PH	None	1/4 of backup heaters
9	MCC 111PH	None	1/4 of backup heaters
10	MCC 112PH	None	1/4 of backup heaters
11	MCC 104R	1Y10	One PRV, charging pumps, pressurizer heaters, letdown control valve, one main feedwater regulating valve.
12	MCC 114R	1Y09	One PRV, pressurizer spray, pressurizer backup heaters, one main feedwater regulating valve, main feedwater pump speed

Table D8. (continued)

Item	Bus Failure Point	Lower Level Bus Failures	Affected Control Functions
13	480-V Unit Bus 11A	None	Half of the proportional heaters, charging pump 13 (also fed by 480-V unit bus 14A via manual switch)
14	480-V Unit Bus 11B	Reactor MCC 114R Instrument Bus 1Y09	Charging pump 11, one PRV, pressurizer spray, pressurizer heaters, one main feedwater regulating valve, main feedwater pump speed
15	4-kV Unit Bus 11	480-V Unit Buses 11A and 11B Reactor MC 114R Instrument Bus 1Y09	Combined functions of 480 V Unit Buses 11A and 11B
16	480-V Unit Bus 12A	MCC 109PH*	1/4 of backup heaters
17	480-V Unit Bus 12B	MCC 110PH	1/4 of backup heaters
18	4-kV Unit Bus 12	480-V Unit Buses 12A and 12B MCC 109PH MCC 110PH	Combined function of 480 V Unit Buses 12A and 12B
19	480-V Unit Bus 13A	MCC 111PH	1/4 of backup heaters
20	480-V Unit Bus 13B	MCC 112PH*	1/4 of backup heaters
21	4-kV Unit Bus 13	480-V Unit Buses 13A and 13B MCC 111PH MCC 112PH	Combined functions of 480 V Unit Buses 13A and 13B

Table D8. (continued)

Item	Bus Failure Point	Lower Level Bus Failures	Affected Control Functions
22	480-V Unit Bus 14A	Reactor MCC 104R Instrument Bus 1Y10	One PRV, half of the proportional heaters, letdown control valve, one main feedwater regulating valve, charging pump 13 (also fed by 480-V unit bus 11A via manual switch).
23	480-V Unit Bus 14B	None	Charging pump 12
24	4-kV Unit Bus 14	480-V Unit Buses 14A and 14B Reactor MCC 104R Instrument Bus 1Y10	Combined functions of 480-V Unit Buses 14A and 14B

*References 4 and 5 indicate MCC 109PH is fed from 480-V unit bus 11B and MCC 111PH is fed from 480-V unit bus 14B.

Table D9. Calvert Cliffs Unit 1 regulating systems multiple power supply failure modes

Item	Bus Failure Point	Affected Control Functions
1	1Y01 and 1Y02	Reactor coolant pressure and pressurizer level, steam dump quick open, and automatic atmospheric steam dump control
2	1Y01 and 1Y09	Pressurizer spray, pressurizer backup heaters, one feedwater regulating system and main feedwater regulating valve, main feedwater pump speed
3	1Y02 and 1Y10	Charging pumps, pressurizer heaters, letdown control valve, one feedwater regulating system and main feedwater regulating valve
4	1Y09 and 1Y10	Charging pumps, pressurizer spray, pressurizer heaters, letdown control valve, main feedwater pump speed, both main feedwater regulating valves

D5. EFFECTS OF VITAL INSTRUMENT BUSES 1Y01 AND 1Y02 CIRCUIT FAILURES ON REGULATING SYSTEMS RESPONSE

The failure of bus 1Y01 or 1Y02 can affect the reactor regulating system, the pressurizer level regulating system, and the reactor coolant pressure regulating system, but, because separate and redundant regulating systems are available for each of these functions, the plant response depends on the systems that were selected for operation at the time of the bus failure. The alternate systems can be selected by the operator through manual switches so that prompt recovery of operating regulating systems is possible for these bus failures. The individual and combined regulating system responses are summarized in Table D10. These effects and the different combinations of regulating system failures are discussed in the following sections.

5.1 INITIAL CONTROL RESPONSE

The initial regulating system response to failure of the 1Y01 or 1Y02 bus consists of the following cases:

1. Reactor regulating system failure
2. Reactor coolant pressure regulating system failure
3. Pressurizer level regulating system failure
4. Reactor and reactor coolant pressure regulating system failure
5. Reactor and pressurizer level regulating system failure
6. Reactor coolant pressure and pressurizer level regulating system failure
7. Reactor, reactor coolant pressure, and pressurizer level regulating system failure.

Reactor Regulating System Failure. Failure of the selected reactor regulating system will result in loss of the atmospheric steam dump area demand function, the atmospheric steam dump quick open permissive, Tavg error alarms, and a lowering of the pressurizer level setpoint. If the plant is operating normally, automatic control response will be to stop all but one charging pump and open the letdown control valve as steps to regulate pressurizer level at the lower indicated setpoint. If a plant trip occurs while the reactor

Table D10. Initial control response of individual regulating system to failures of vital instrument buses 1Y01 and 1Y02

Regulating System	Failure	Control Response[1]
Reactor	Power to selected system fails	Atmospheric steam dump area demand goes to zero. Atmospheric steam dump quick open permissive not allowed. Pressurizer level setpoint fails to lower level. Tavg - Tref high/low alarm fails.
	Power to non-selected system fails	Zero current from half of the sensors. Atmospheric steam dump area demand fails closed. Atmospheric steam dump quick open permissive not allowed. Pressurizer level setpoint lowered. Tavg - Tref high/low alarm indicates Tavg too low.
Reactor Coolant Pressure	Power to selected system fails	Pressurizer spray valve closes. Proportional heaters fail on. Backup heaters turn on.
Pressurizer Level	Power to selected system fails	Letdown control valve closes. Pressurizer level indicates low which starts backup charging pump(s). All heaters de-energized due to apparent lo-lo level indication.
Feedwater	Power to selected system fails	No response. 1Y01 alternate (SG11) is 1Y09; 1Y02 alternate (SG12) is 1Y10. Transfer to alternate bus is automatic.

[1]Control response is for loss of power to single regulating system. Multiple regulating system failure response is described in the discussion.

regulating system power supply is failed, there will not be a turbine bypass valve or atmospheric steam dump valve quick open and secondary steam pressure control will be provided by the code safety valves.

If the reactor regulating system power supply fails while the turbine bypass or atmospheric steam dump valves are in operation, the quick open function will be lost and the atmospheric steam dump valves will close. The turbine bypass valves will regulate on steam pressure and manual control of the atmospheric steam dump valves will be available. Additional pressure control will be provided by the code safety valves if required. The regulating system failure can be corrected by manually selecting the alternate reactor coolant pressure regulating system. Loss of power 1Y01 or 1Y02 is alarmed in the control room.

Reactor Coolant Pressure Regulating System. Loss of power to the operating reactor coolant pressure regulating system will close the pressurizer spray valve and turn on the proportional and backup pressurizer heaters. The pressurizer level regulating system will participate by closing the letdown control valve and turning on the backup charging pump(s) to maintain pressurizer level. This will introduce a positive pressure transient that could result in a high pressure reactor trip.

The pressurizer heaters and spray valves may be controlled manually from non-vital instrument power. The regulating system failure can be corrected by manually selecting the alternate reactor coolant pressure regulating system. Loss of power 1Y01 or 1Y02 is alarmed in the control room.

Pressurizer Level Regulating System. Loss of power 1Y01 or 1Y02 to the selected pressurizer level regulating system will close the letdown control valve, start the selected backup charging pump(s), and de-energize the pressurizer heaters. This will produce a transient of decreasing pressure and increasing pressurizer level. Unless terminated, this could lead to filling the pressurizer. There may be a low or high pressure reactor trip. The letdown control valve can still be controlled manually through non-vital instrument power. These effects can be corrected by manually selecting the alternate pressurizer level regulating system.

Reactor and Reactor Coolant Pressure Regulating Systems Failure. If both the reactor regulating system and the reactor coolant pressure regulating system are selected from the failed bus, the net effect will be the combination of the individual reactor regulating system and reactor coolant pressure regulating system failures as previously described. A high pressure reactor trip is possible followed by dependence on the code safety valves for secondary steam pressure control. These automatic regulating functions can be restored by manually selecting the alternate reactor and pressurizer level regulating systems.

Reactor and Pressurizer Level Regulating Systems Failure. If both the reactor regulating system and the pressurizer level regulating system are selected from the failed bus, the pressurizer level regulating system failure dominates the failed pressurizer level setpoint signal from the reactor regulating system. The pressurizer response will be the same as described for the failure of the pressurizer level regulating system by itself. The additional failure of the reactor regulating system will affect atmospheric steam dump and turbine bypass control as described for failure of this system alone. The net result will be an increasing pressurizer level transient combined with decreasing reactor coolant pressure and loss of the atmospheric steam dump quick open or reactor Tavg atmospheric steam dump and turbine bypass area demand if there is a reactor/turbine trip. These automatic regulating functions can be restored by manually selecting the alternate reactor and pressurizer level regulating systems.

Reactor Coolant Pressure and Pressurizer Level Regulating Systems Power Failure. Loss of power to the operating reactor coolant pressure and pressurizer level regulating systems will result in loss of the pressurizer heaters, starting of the backup charging pump(s), and closure of the letdown control valve caused by failure of the pressurizer level regulating system and closure of the pressurizer spray valve caused by failure of the reactor coolant pressure regulating system. The resulting reactor coolant pressure and pressurizer level transient will be the net effect of the loss of heaters combined with reduced spray and an increase in reactor coolant inventory from the charging pumps. Manual control of the letdown control valve and the pressurizer spray valve are available through non-vital instrument power. The automatic regulating functions can be restored by manually selecting the alternate reactor coolant pressure and pressurizer level regulating systems.

Reactor, Reactor Coolant Pressure, and Pressurizer Level Regulating Systems Power Supply Failure. Loss of power to the reactor, reactor coolant pressure, and pressurizer level regulating systems will result in the effects of the combined loss of power to the pressurizer level and reactor coolant pressure regulating systems with the loss of atmospheric steam dump quick open and Tavg area demand functions associated with the reactor regulating system. An increasing pressurizer level and decreasing reactor coolant pressure transient will be initiated with dependence on the code safety valves for secondary pressure control in the event of a reactor trip. These automatic regulating functions can be restored by selecting the alternate reactor, pressurizer level, and reactor coolant pressure regulating systems.

5.2 SUBSEQUENT CONTROL

It is expected that the operators will select the alternate regulating systems as required following a failure of vital instrument bus 1Y01 or 1Y02 and that normal regulating system functions will be available for subsequent plant control.

D6. EFFECTS OF INSTRUMENT BUSES 1Y09 AND 1Y10 CIRCUIT FAILURES ON REGULATING SYSTEMS RESPONSE

The failure of non-vital instrument bus 1Y09 affects reactor coolant pressure regulation through failed output control modules and relays, and affects feedwater flow regulation through loss of power to one feedwater regulating valve and the feedwater pump speed controller. These effects are summarized in Table D11.

The failure of non-vital instrument bus 1Y10 will affect pressurizer level control through failed output relays and will affect the steam generator 12 feedwater regulating valve through loss of power to air control solenoids. These effects are summarized in Table D12.

6.1 INITIAL CONTROL RESPONSE

Failure of instrument bus 1Y09 will result in the pressurizer spray valve closure due to loss of power to the spray valve control station. The pressurizer backup heaters will fail off due to loss of power to the backup heater control relays. The main feedwater regulating valve for steam generator 11 will fail as-is due to loss of power to air control solenoid valves. The main feedwater pump speed will fail as-is due to loss of power to the pump speed controller. The reactor coolant system may experience decreasing pressure due to the backup heater failures.

Failure of instrument bus 1Y10 will deenergize all pressurizer heaters due to loss of power to the lo-lo level heater protection relays. The backup charging pump(s) will be started due to loss of power to their control relays. This will lead to a transient of increasing pressurizer level and decreasing reactor coolant pressure. The steam generator 12 feedwater flow regulating valve will fail as-is.

6.2 SUBSEQUENT CONTROL

Correct diagnosis of the 1Y09 power supply failure will contribute to operator interpretation of the changes in reactor coolant pressure. If there is a

Table D11. Initial control response of affected regulating system to failures of instrument bus 1Y09

Regulating System	Failure	Control Response
Reactor Coolant Pressure	Bus fails	Pressurizer spray valve fails closed. Backup heaters deenergized.
Feedwater	Bus fails	SG11 main feedwater regulating valve fails as-is.
Feedwater Pump Speed	Bus fails	Feedwater pump speed fails as-is.[1]

[1]Reference 3 indicates that pump speed runs back to idle speed.

Table D12. Initial control response of affected regulating systems to failures of instrument bus 1Y10

Regulating System	Failure	Control Response
Pressurizer Level	Bus fails	De-energize all pressurizer heaters due to apparent lo-lo level. Start backup charging pump(s). Letdown control valve fails closed.
Feedwater	Bus fails	SG12 feedwater regulating valve fails as-is. Pneumatic leakage may allow valve to slowly open or close.

reactor trip, the steam generator 11 level will increase due to the constant feedwater flow. This flow will not be terminated by an automatic control function but can be stopped by manually tripping the feedwater pump turbine.

The pressurizer heaters will remain unavailable due to the dominance of the lo-lo level protection relay over other control points. The steam generator 11 main feedwater regulating valve will remain open. The feedwater pump speed control will regulate the differential pressure across the steam generator 12 feedwater regulating valve when this valve has a larger differential pressure drop. Feedwater pump speed will run back to minimum recirculation as designed if there is an auxiliary feedwater actuation. The charging pumps can be started or stopped manually.

Operator identification of 1Y10 power supply failure will contribute to the correct interpretation of the initially increasing pressurizer level combined with decreasing reactor coolant pressure.

D7. EFFECTS OF DOUBLE INSTRUMENT BUS FAILURES ON REGULATING SYSTEMS RESPONSE

The effects of selected double bus failures were evaluated with respect to regulating system response. The double failures considered were selected on the basis of introducing a total loss of power to regulating system electronic modules, introducing regulating system control failures that affect primary system water inventory and heat removal capacity, and the availability of maintenance ties as a potential common cause.

7.1 EFFECTS OF VITAL INSTRUMENT BUSES 1Y01 AND 1Y02 FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of vital instrument buses 1Y01 and 1Y02 will result in a loss of power to the electronic modules in the reactor regulating systems, the reactor coolant pressure regulating system, and the pressurizer level regulating system. These failures will affect control response for reactor coolant pressure and pressurizer level control.

7.1.1 Initial Control Response

A reactor trip will be initiated due to the loss of power to two protection channels. The pressurizer relief valves will automatically open due to the trip.

The atmospheric steam dump and turbine bypass valves will not quick open due to the loss of both reactor regulating systems. The turbine bypass valves will open under the control of the steam generator outlet pressure controller. This delayed opening may lead to operation of the steam line code safety valves. If the 1Y01 bus failure were due to a failure of dc bus 11, the turbine bypass valves will receive a quick close signal due to loss of dc power through the low condenser vacuum switch.

The pressurizer heaters will turn off due to apparent lo-lo pressurizer level and the backup charging pumps will start due to apparent low pressurizer level associated with loss of power to the pressurizer level regulating system modules. The letdown throttle valve and the pressurizer spray valve will close due to loss of signal from regulating system modules.

The net effect will be a reactor trip followed by reduced heat removal capability through the atmospheric steam dump and turbine bypass valves.

7.1.2 Subsequent Control

The proportional and backup pressurizer heaters will remain unavailable due to the lo-lo level interlock in the pressurizer level regulating system. The pressurizer relief valves, the pressurizer spray valve, and the letdown throttle valve can be controlled manually.

The atmospheric steam dump valves can be controlled manually and the turbine bypass valves will regulate on steam pressure or can be controlled manually unless the 1Y01 failure was associated with a dc bus 11 failure, resulting in a quick close signal to the turbine bypass valves.

With promptly instituted remedial action by the operator to manually close the PRVs or their isolation valves, the impact of the small LOCA is negligible. Recovery of either vital bus also results in automatic closure of the PRVs.

Without remedial actions, a coupled small LOCA and failure to automatically start HPSI will occur (Reference 3). However, the automatic start of the backup charging pumps will moderate the effect of the HPSI initiation failure.

7.2 EFFECTS OF INSTRUMENT BUSES 1Y01 AND 1Y09 FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of buses 1Y01 and 1Y09 will result in a loss of power to the steam generator 11 regulating system. The reactor coolant pressure regulating system and the feedwater pump speed control system will also be affected if selected from bus 1Y01 at the time of failure.

7.2.1 Initial Control Response

The pressurizer spray valve will close and the pressurizer heaters will turn on due to the loss of bus 1Y09 to reactor coolant pressure regulating system components.

Steam generator 11 will receive a constant feedwater supply due to loss of power to the main feedwater regulating valve positioner and loss of main feedwater pump speed control. Normal level indication for steam generator 11 will fail low due to loss of power to the regulating system. The backup charging pumps will start and the letdown throttle valve will close if the pressurizer level regulating system is selected from bus 1Y01 at the time of failure.

7.2.2 Subsequent Control

Operable reactor, reactor coolant pressure, and pressurizer level regulating systems can be selected from bus 1Y02 if originally selected from bus 1Y01. The pressurizer spray valve will remain closed due to loss of 1Y09 power to the control station. Steam generator 11 feedwater flow will remain constant unless the feedwater pump is manually tripped or the MFIV is closed on indicated high steam generator level.

7.3 EFFECTS OF INSTRUMENT BUSES 1Y02 AND 1Y10 FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of buses 1Y02 and 1Y10 will result in a loss of power to the steam generator 12 regulating system. The reactor coolant pressure and pressurizer level regulating systems will be affected by loss of 1Y10 power to regulating system components. The reactor regulating system will be affected if the operating system is selected from bus 1Y02 at the time of failure.

7.3.1 Initial Control Response

The pressurizer heaters will turn off and the backup charging pumps will start due to loss of bus 1Y10 to pressurizer level regulating system components.

The feedwater regulating system for steam generator 12 will fail and the main feedwater regulating valve for this generator will freeze as-is. The pressurizer spray valve will close if the reactor coolant pressure regulating system is selected to bus 1Y02 at the time of failure.

7.3.2 Subsequent Control

The reactor, reactor coolant pressure, and pressurizer level regulating systems can be switched to bus 1Y01 if selected from bus 1Y02 at the time of failure. The proportional and backup pressurizer heaters will remain off and the letdown throttle valve will remain closed due to the loss of bus 1Y10.

Normal feedwater flow and steam generator level indication will remain failed for steam generator 12 combined with the associated main feedwater regulating valve remaining fixed in position. The main feedwater pump speed control will remain operational and run back to minimum recirculation following auxiliary feedwater actuation.

7.4 EFFECTS OF INSTRUMENT BUSES 1Y09 AND 1Y10 FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of buses 1Y09 and 1Y10 will affect the reactor coolant pressure regulating system, the pressurizer level regulating system, the main feedwater regulating valve position control, and feedwater pump speed control.

7.4.1 Initial Response

The pressurizer proportional and backup heaters will fail off due to loss of power to the lo-lo level interlock relays. The pressurizer spray valve will close and the letdown throttle valve will close due to loss of power to control components. The backup charging pumps will start due to loss of power to control relays. The main feedwater regulating valves will fail as-is and the main feedwater pump speed control will fail as-is. The net effect will be a transient of increasing pressurizer level combined with a loss of main feedwater control.

7.4.2 Subsequent Control

None of the failed control function can be recovered without restoring the associated instrument power bus. Main feedwater flow can be terminated by manually tripping the feedwater pump at the pump location.

D8. EFFECTS OF 125-V dc BUSES 11 AND 21 FAILURES ON REGULATING SYSTEMS RESPONSE

DC buses 11 and 21 affect reactor coolant pressure control, pressurizer relief valve control, charging pump control, and main turbine EHC through loss of dc power to circuit breakers and relays used to energize and de-energize the controlled equipment. Atmospheric steam dump and turbine bypass valve control will be affected through loss of the quick open function and a quick close demand for the turbine bypass valves. These effects are summarized in Table D13.

8.1 INITIAL CONTROL RESPONSE

Charging pump 11 or 12 will fail as-is depending on which bus fails due to loss of power to operate the 480-V motor control circuit breaker. The pressurizer relief valves will fail closed or remain closed due to loss of power to the control relay. The turbine bypass valves will receive a quick close signal due to loss of power to the quick close solenoid valves and the quick open function will be lost for both the turbine bypass and atmospheric steam dump valves. For loss of power to dc bus 11, the main turbine will trip because of loss of power to the turbine protection system. Reactor coolant pressure relief will be provided through the pressurizer code safety valves and steam pressure control will be provided through the steam code safety valves.

8.2 SUBSEQUENT CONTROL

Charging pump start/stop control can be obtained by selecting the two charging pumps not affected by the failed dc bus. The pressurizer relief valve can be operated manually. Steam pressure control will remain a code safety valve function. Manual control of the atmospheric steam dump valves is possible.

8.3 EFFECTS OF MULTIPLE DC BUS FAILURES

The dc bus system was reviewed for potential common cause failure. No significant cause for multiple failure was identified. If multiple failure

Table D13. Initial control response of affected regulating systems to failures of 125-V dc buses 11 and 21

Regulating System	Failure	Control Response
Reactor Coolant Pressure	Bus 11 or 21 fails	Proportional heater bus breaker (1/2 proportional heaters per bus) must be closed manually if it trips.
Pressurizer Relief Valve Control	Bus 11 fails	Loss of relief valve control indication and automatic open function. Valve fails closed or remains closed. Valves may be controlled manually.
Pressurizer Level		
Charging Pump 11	Bus 11 fails	Affected charging pump motor control breaker fails as-is with manual control at the breaker. Loss of control indication.
Charging Pump 12	Bus 21 fails	
Charging Pump 13	Bus 11 or 21 fails	
Turbine Bypass and Atmospheric Steam Dump	Bus 11 fails	Turbine bypass valves quick close. Atmosphere steam dump valves will not quick open. Valve position indication lost.
Turbine Generator Control	Bus 11 fails	A turbine trip will occur which a will cause a reactor trip. A vital bus to each unit will also fail.

did occur, the effects on regulating system response would be similar to those reported for multiple failures of the vital instrument buses. Additional effects could result from other safety equipment powered from dc buses.

D9. EFFECTS OF MOTOR CONTROL CENTER (MCC) 109PH, 110PH, 111PH AND 112PH ON REGULATING SYSTEMS RESPONSE

Each of these motor control centers provides ac power to one fourth of the pressurizer backup heaters. These effects are summarized in Table D14.

9.1 INITIAL CONTROL RESPONSE

The pressurizer backup heater capacity will be reduced by one fourth for each motor control center failure. This will affect the backup heater heating rate, but should not introduce a substantial change in system control.

9.2 SUBSEQUENT CONTROL

Pressurizier heater control functions will remain operational at a reduced heat rate.

Table D14. Initial control response of affected regulating systems to failures of motor control centers (MCCs) 109PH, 110PH, 111PH, and 112PH

Regulating System	Failure	Control Response
Reactor Coolant Pressure	Single MCC fails	Backup heaters powered by failed MCC fail 25% of capacity lost for each MCC Failure.

D10. EFFECTS OF MOTOR CONTROL CENTER (MCC) 104R AND 114R ON REGULATING SYSTEMS RESPONSE

These motor control centers combine the loss of power to one pressurizer relief valve solenoid and the associated relief isolation valve with the failures of non-vital instrument bus 1Y09 or 1Y10. These effects are summarized in Tables D15 and D16.

10.1 INITIAL CONTROL RESPONSE

The failure of MCC 104R will combine the loss of power to one pressurizer relief valve, which normally fails closed, and loss of power to the isolation valve for the second pressurizer relief valve with the regulating system response for the loss of non-vital instrument bus 1Y10 as discussed in Section 6. The other pressurizer relief valve will remain operational.

The failure of MCC 114R will combine the loss of power to one pressurizer relief valve which normally fails closed and loss of power to the isolation valve for the second pressurizer relief valve with the regulating system response for the loss of non-vital instrument bus 1Y09 as discussed in Section 6. The other pressurizer relief valve will remain operational.

10.2 SUBSEQUENT CONTROL

Subsequent control will be the same as that described for the failures of instrument bus 1Y10 and/or 1Y09 as discussed in Sections 6 and 7. If pressurizer relief valve operation is demanded and the operable valve sticks in the open position, it cannot be isolated until the associated MCC power is restored.

Table D15. Initial control response of affected regulating systems to failures of motor control center (MCC) 104R

Regulating System	Failure	Control Response
Reactor Coolant Pressure	MCC 104R	One pressurizer relief valve fails closed or remains closed. The isolation valve for the second pressurizer relief valve fails as-is.
Pressurizer Level	1Y10	Backup charging pump(s) turned on. De-energize all pressurizer heaters due to apparent lo-lo level. Letdown control valve fails closed.
Feedwater	1Y10	SG12 feedwater regulating valve fails as-is. Pneumatic leaks in the valve may cause it to close or open gradually.

Table D16. Initial control response of affected regulating systems to failures of motor control center (MCC) 114R

Regulating System	Failure	Control Response
Reactor Coolant Pressure	MCC 114R	One pressurizer relief valve fails closed or remains closed the isolation valve for the second pressurizer relief valve fails as-is.
Pressurizer Level	1Y09	Pressurizer spray valve fails closed. Backup heaters de-energized.
Feedwater	1Y09	SG11 feedwater regulating valve fails as-is.
Feedwater Pump Speed	1Y09	Feedwater pump speed fails as-is.[1]

[1]Reference 3 indicates that pump speed runs back to idle speed.

D11. EFFECTS OF 480-V UNIT BUSES 11A AND 11B (4-kV UNIT BUS 11) FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of 480-V unit bus 11A will de-energize one half of the pressurizer proportional heaters. Failure of 480-V unit bus 11B will fail reactor MCC 114R and instrument bus 1Y09 as discussed in Section 10. Failure of 480-V unit bus 11B will fail one charging pump. Failure of 4-kV unit bus 11 will fail both 480-V unit buses 11A and 11B. These effects are summarized in Table D17.

11.1 INITIAL CONTROL RESPONSE

Failure of the 480-V unit bus 11A will reduce the proportional heater capacity by one half and fail charging pump 13 if running from this bus. This should not substantially affect reactor coolant pressure or pressurizer level control response.

Failure of 480-V unit bus 11B will have the same effect as the failure of motor control center 114R as described in Section 10, involving pressurizer spray valve closure, loss of all pressurizer heaters, failure of steam generator 11 feedwater regulating valve as-is, and failure of the main feedwater pump speed as-is. Failure of 480-V unit bus 11B will fail charging pump 11 if running.

Failure of 4-kV unit bus 11 will have the same effect as the failure of the 480-V bus 11B due to the loss of all heaters through instrument bus 1Y09 and the loss of one of three available charging pumps.

11.2 SUBSEQUENT CONTROL

Subsequent regulating system operation should not be substantially affected by failure of 480-V unit bus 11A. Charging pump 13 can be fed by 480-V unit bus 14A via manual switch.

Table D17. Initial control response of affected regulating systems to failures of 480-V buses 11A and 11B (4-kV unit bus 11)

Regulating System	Failure	Control Response
Reactor Coolant Pressure	480-V Unit Bus 11A	50% of the proportional heaters fail.
Pressurizer Level	480-V Unit Bus 11A	Charging pump 13 fails if running but can be manually switched to alternate 480-V unit bus 14A.
Reactor Coolant Pressure	480-V Unit Bus 11B (MCC 114R/1Y09)	One pressurizer relief valve fails closed or remains closed. The isolation valve for the second pressurizer relief valve fails as-is.
Pressurizer Level	480-V Unit Bus 11B (MCC 114R/1Y09)	Pressurizer spray valve fails closed. Backup heaters de-energized. Charging pump fails if running.
Feedwater	480-V Unit Bus 11B (MCC 114R/1Y09)	SG11 feedwater regulating valve fails as-is.
Feedwater Pump Speed	480-V Unit Bus 11B (MCC 114R/1Y09)	Feedwater pump speed fails as-is.[1]
All of above	4-kV Unit Bus 11	Combined response above.

[1]Reference 3 indicates that pump speed runs back to idle speed.

Subsequent regulating system controls following failure of 480-V unit bus 11B or 4-kV unit bus 11 will be the same as described for the failure of reactor MCC 114R in Section 10. This will involve loss of pressurizer heaters, pressurizer spray, and the requirement to manually trip the main feedwater turbine to reduce steam generator 11 main feedwater flow.

D12. EFFECTS OF 480-V UNIT BUSES 12A AND 12B (4-kV UNIT BUS 12) FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of 480-V unit bus 12A or 12B will each de-energize one quarter of the pressurizier backup heaters. Failure of 4-kV unit bus 12 will de-energize one half of the pressurizer backup heaters. These effects are summarized in Table D18.

12.1 INITIAL CONTROL RESPONSE

Failure of 480-V unit bus 12A will de-energize one quarter of the backup heaters due to loss of power to MCC 109PH. Failure of 480-V unit bus 12B will de-energize another one fourth of the backup heaters due to loss of power to MCC 110PH. Failure of 4-kV unit bus 12 will de-energize one half of the pressurizer backup heaters due to the loss of power to both MCC 109PH and 110PH.

12.2 SUBSEQUENT CONTROL

The heat rate of the backup heaters will be reduced by one quarter or one half as noted above. The proportional heaters will remain operational. This is not expected to substantially affect the reactor coolant pressure regulating functions.

Table D18. Initial control response of affected regulating systems to failures of 480-V unit buses 12A and 12B (4-kV unit bus 12)

Regulating System	Failure	Control Response
Reactor Coolant Pressure	480-V Unit Bus 12A or 12B	Same as failing MCC 109PH or 110PH. (1/4 of backup heaters each).
Reactor Coolant Pressure	4-kV Unit Bus 12	Fails 1/2 of backup heaters.

D13. EFFECTS OF 480-V UNIT BUSES 13A AND 13B (4-kV UNIT BUS 13) FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of 480-V unit bus 13A or 13B will each de-energize one quarter of the pressurizier backup heaters. Failure of 4-kV unit bus 13 will combine these failures with the loss of one half of the pressurizer backup heaters. These effects are summarized in Table D19.

13.1 INITIAL CONTROL RESPONSE

Failure of 480-V unit bus 13A will de-energize one quarter of the backup heaters due to loss of power to MCC 111PH. Failure of 480-V unit bus 13B will de-energize another one fourth of the backup heaters due to loss of power to MCC 112PH. Failure of 4-kV unit bus 13 will de-energize one half of the pressurizer backup heaters due to the loss of power to both MCC 111PH and 112PH.

13.2 SUBSEQUENT CONTROL

The heat rate of the backup heaters will be reduced by one quarter or one half as noted above. The proportional heaters will remain operational.

Table D19. Initial control response of affected regulating systems to failures of 480-V unit buses 13A and 13B (4-kV unit bus 13)

Regulating System	Failure	Control Response
Reactor Coolant Pressure	480-V Unit Bus 13A or 13B	Same as failing MCC 111PH or MCC 112PH.
Reactor Coolant Pressure	4-kV Unit Bus 13	1/2 backup heaters.

D14. EFFECTS OF 480-V UNIT BUSES 14A AND 14B (4-kV UNIT BUS 14) FAILURES ON REGULATING SYSTEMS RESPONSE

Failure of 480-V unit bus 14A will de-energize one pressurizer relief valve, start the selected charging pump(s), turn off the pressurizer heaters, close the letdown control valve, and fail one main feedwater regulating valve as-is. Failure of 480-V unit bus 14B will fail one charging pump. Failure of 4-kV unit bus 14 will fail both 480-V unit buses 14A and 14B. These effects are summarized in Table D20.

14.1 INITIAL CONTROL RESPONSE

Failure of the 480-V unit bus 14A will have the same effects as the failure of motor control center 104R and instrument bus 1Y10 as described in Section 10. These failures will de-energize one pressurizer relief valve, de-energize the pressurizer heaters, fail charging pump 13 if running, close the letdown control valve, and freeze the steam generator 12 main feedwater regulating valve as-is.

Failure of 480-V unit bus 14B will fail charging pump 12.

Failure of 4-kV unit bus 14 will have the same effects as the failure of 480-V unit bus 14A combined with the loss of one of three available charging pumps.

14.2 SUBSEQUENT CONTROL

Subsequent control following the failure of 480-V unit bus 14A or 4-kV unit bus 14 will be the same as the failure of MCC 104R as described in Section 10. Charging pump 13 can be manually switched to 480-V unit bus 11A if required. Subsequent control following the failure of 480-V unit bus 14B will not be affected due the ability to select two operating charging pumps.

Table D20. Initial control response of affected regulating systems to failures of 480-V unit buses 14A and 14B (4-kV unit bus 14)

Regulating System	Failure	Control Response
Reactor Coolant Pressure	480-V Unit Bus 14A (MCC 104R/1Y10)	50% of the proportional heaters fail. One pressurizer relief valve fails closed or remains closed. The isolation valve for the second pressurizer relief valve fails as-is.
Pressurizer Level	480-V Unit Bus 14A (MCC 104R/1Y10)	Charging pumps turned on. De-energize all pressurizer heaters due to apparent lo-lo level. Letdown control valve fails closed.
Feedwater	480-V Unit Bus 14A (MCC 104R/1Y10)	SG12 feedwater regulating valve fails as-is.
Pressurizer Level	480-V Unit Bus 14B	Charging pump 12 fails off.
All of above	4-kV Unit Bus 14	Combined response above.

APPENDIX D REFERENCES

1. "Calvert Cliffs Final Safety Analysis Report," Baltimore Gas and Electric Co., July 1982.

2. Miscellaneous Calvert Cliffs Unit 1 Drawings received from Baltimore Gas and Electric Company.

3. "Pressurized Thermal Shock Evaluation of the Calvert Cliffs Unit 1 Nuclear Power Plant," Oak Ridge National Laboratory PTS Study Group, October 9, 1984, NUREG/CR-4022 (Draft).

4. Calvert Cliffs Unit 1, OI-27D, Rev. 10, January 25, 1984.

5. Calvert Cliffs Unit 1, AOP-16, Rev. 5, February 1983.

APPENDIX E

Reply to BG&E Comments on the May 31, 1985
Draft Final Report

NOTE: The authors appreciate BG&E's thorough and helpful review of the draft report. It should be noted that BG&E was not allowed (by NRC ruling) to comment on the final version, so it should not be assumed that the final form of the report includes their last word on all issues. Further, we chose not to make any changes at all in response to many of BG&E's comments, so an additional caveat must be made that this report does not necessarily represent the utility's positions or opinions. In general, only those licensee comments that resulted in, or coincided with, a change to the draft report are commented on in this appendix. The reader should also note that BG&E references to specific page numbers in the report refer to pages in the May 31, 1985, draft version, and generally do not correspond to those in the final version.

The BG&E letter and our responses follow.

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ELECTRIC ENGINEERING
DEPARTMENT

August 26, 1985

Mr. A. P. Malinauskas, Director
NRC Programs
Oak Ridge National Laboratory
P. O. Box X
Oak Ridge, TN 37831

Dear Mr. Malinauskas:

Subject: Technical Review Comments of Draft NUREG/CR-4265, "An Assessment of the Safety Implications of Control at the Calvert Cliffs Nuclear Power Plant"

The Baltimore Gas and Electric Company staff has technically reviewed draft NUREG/CR-4265. Our comments are contained in Attachment 1. Some of these comments were discussed verbally in a telephone conversation with Messrs. Ball and Stone of ORNL on August 2, 1985. I hope that these comments are helpful and can be used to improve the technical accuracy and completeness of this report. We would like the opportunity to review the next draft of the report and provide comments, as appropriate, prior to publication.

If you have any questions, please do not hesitate to contact me at (301) 234-6116.

Very truly yours,

S. M. Mirsky

S. M. Mirsky
A-47 Project Coordinator

SMM/vd

Attachment

cc: Messrs. S. J. Ball (ORNL)
R. S. Stone (ORNL)
D. L. Basdekas, RES/NRC

GENERAL COMMENTS

Several major comments and findings are repeatedly discussed throughout this report. The following comments are provided regarding these items.

1. Calvert Cliffs is depicted as a nuclear power plant with "major parameters . . . almost entirely under manual (operator) control." This statement is wrong. Pressurizer pressure and level and steam generator level, which constitute important major parameters, are automatically controlled at Calvert Cliffs. The comparison of Calvert Cliffs to Oconee, which is characterized as using a "completely integrated and extensive control system," is misleading and reflects a basic lack of knowledge about differences between the Babcock and Wilcox (B&W) and Combustion Engineering (CE) NSSS designs. The large U-tube steam generator and the corresponding secondary side inventory in CE plants result in an inherently long response time to secondary side malfunctions when compared to the once-through steam generator B&W design. This major design difference dictates the need for a "completely integrated and extensive control system" in B&W plants and obviates such a system for CE plants. This design difference is not discussed in the Calvert Cliffs report. Finally, specific mention of differences in the shutoff head for HPSI pumps at Calvert Cliffs and Oconee (1275 psia for Calvert Cliffs vs 2800 psia for Oconee) is an irrelevant comparison of one design difference. The author incorrectly implies that the Oconee pump is a safer feature by the inclusion of this single comparison. One example of the incorrectness of the generalization is that the lower shutoff head HPSI pump is actually safer for potential pressurized thermal shock transients.

2. One of the two major findings of this study involves the steam generator overfill scenario. BG&E agrees that there are postulated events in which the steam generator can be overfed. However, the emphasis on the importance of such an event is out of proportion to a realistic appraisal. SG overfeeding during full or significant power levels while steaming to the turbine results in an extremely slow rise in SG level. SG overfeeding at low or hot zero power will fill the SG more rapidly, but BG&E operators have demonstrated their proficiency in mitigating this event well before overfilling occurs in both operating experience and training. This report consistently downplays or underrates operator action. Feedwater runback from the high steam generator level trip and SGIS initiated by overfeed induced low SG pressure are not accounted for in this report. SGIS causes MSIV closure even in liquid filled piping. Also, the probability of an overfeed at low power should be weighed within the framework of the small fraction of time in which Calvert Cliffs is at such power levels and the plant feedwater system configurations at such power levels. Finally, the questionable technical conclusions regarding the consequences of SG overfill (i.e., steam line rupture and SGTR) must be discussed in terms of the current understanding of this complex phenomenon. These are not probable consequences of a steam generator overfill. The report gives no credit for MSIV closure or steam line pipe seismic supports in this event. Steam line mechanical restraints and supports are designed to sustain concurrently-acting thermal, seismic and seismic anchor movement loads on the piping system. The supports are designed to carry dead weight and insulation loads and the weight of the contents in the piping system. Supports permit free movement in longitudinal and lateral direction caused by thermal expansion or contraction and earthquakes. Restraints and supports at the isolation valves and stop valves are designed to carry, in addition to the above mentioned loads, the dynamic loads due to sudden closure of stop valves.

3. The second major finding of this study was the apparent lack of a procedure for operator action in the case of a small break LOCA greater than charging pump capability (132 gpm) but less than the (0.1 ft^2) smallest LOCA analyzed in the FSAR. Based on Emergency Procedure Guidelines funded by the CE Owners Group and documented in CEN-152, BG&E has developed new Emergency Operating Procedures (EOPs) including EOP-500 (enclosed) for LOCAs. Although these new EOPs will not be officially effective until December 31, 1985, we are currently training operators on these EOPs. CE has analyzed small break LOCAs as small as 0.0005 ft^2 (the PORV area is 0.00754 ft^2 in CEN-114-P. These analyses showed that the primary coolant system deprssurizes below the HPSI pump shutoff head and that 10 CFR 50 Appendix K PCT limits are not reached for these LOCAs.

Two of the failures identified in this study as small break LOCA initiators are invalid. First, operating pressurizer heaters without water above them is an extremely low probability event requiring multiple independent failures. Furthermore, CE analyses have shown that steam covered operating heaters would not breach the pressurizer pressure boundary.

The second failure discussed as a small break LOCA initiator was a loss of RCP seal integrity. A loss of component cooling water to the RCP seal assembly will not result in a small break LOCA. The Byron-Jackson pump seal assemblies used at Calvert Cliffs have been demonstrated under a CE test program to be capable of operation in the absence of cooling water flow for extended periods of time (at least 30 minutes) without exceeding seal leakage limits. Seal cooling is not required for an idle pump. As a precautionary measure to protect the non-metallic seal components from overheating (which could result in the need to replace the seal assembly), the vendor recommends that pump operation be ceased within 10 minutes of the loss of component cooling water. The RCP seals are well instrumented, and alarms are provided in the control room to alert the operators of a loss of component cooling water or increased seal face temperature. Operator guidance for responding to a loss of RCP seal cooling is provided in Abnormal Operating Procedure 7C, "Loss of Component Cooling." The importance of controlled restoration of CCW during event recovery is stressed. In addition, our new emergency operating procedures developed pursuant to NUREG-0737, Item I.C.1 contain operating limits consistent with pump operating guidelines provided by Combustion Engineering and Byron Jackson. These new procedures are:

EOP-200Loss of Off-Site Power
EOP-300Total Loss of All Feedwater
EOP-400Excess Steam Demand
EOP-500Loss of Coolant Accident
EOP-700Station Blackout
EOP-800Functional Recovery Guideline

The subject guidance is currently included in the operator requalification training program at Calvert Cliffs.

The NRC was informed of the above during a meeting with BG&E, Arkansas Power and Light and Combustion Engineering on March 13, 1985 to discuss RCP seal integrity following a loss of offsite power (NUREG-0737, Item II.K.3.25). As a result of that meeting, BG&E conducted operator interviews and confirmed the effectiveness of the training program with regards to RCP operation in the absence of component cooling water.

Based on experience gained from several operational occurrences at CE plants (i.e., San Onofre, St.Lucie) and the results of the CE test program, the maximum expected (RCS) leakage due to a loss of CCW would be well under 10 gpm per pump, even if the pumps were left running for significant periods of time (e.g., 30 minutes).

In summary, the potential consequences of a loss of RCP seal cooling are that the technical specification limits for RCS leakage (10 gpm) may be exceeded if the pumps are not stopped within ten minutes in accordance with operator guidelines. However, adequate procedures and training exist at Calvert Cliffs to preclude this event. In any case, the maximum expected RCS leakage from all four pumps combined would be less than the makeup capacity of one charging pump (44 gpm). This small amount of leakage is not classified as a LOCA unless no charging pumps are available.

4. Throughout this report, nebulous words are used without quantification and substantiation by analysis. Many descriptions and statements are subjective or are irrelevant to Calvert Cliffs. Negative connotations are utilized indiscriminately and, in some cases, without basis.

   Some underlined examples:

   Page 1-2 "Excessively frequent challenges. . ."
   Page 1-3 "Time available . . . is short"
   Page 1-5 "Time available . . . relatively small . . ."
   Page 1-8 "Bothersome challenges to the plant protection system"
   Page 2-6 "Safety threatening scenarios . . ."
   Page 3-11 " . . . natural allotment of operator errors . . ."
   Page 3-37 "Human error will be forever around . . ."
   Page 9-2 "The answer . . . is tentatively affirmative."
   Page 9-3 " . . . soft area of plant design"
   Page 9-4 "The conditions found in Calvert Cliffs-1 are not frightful . . ."

5. There is a general reluctance to credit operator actions throughout the report. In those cases where operator actions were credited, unreasonable failure probabilities were assumed and applied. The typical value for recovery failure was 0.1/event, regardless of how much time was available or the existence of specific procedure guidance.

ATTACHMENT 1

SPECIFIC COMMENTS

1. Page 1-1. The word "old" is improper - the proper term would be a plant of "early vintage" or "1970's vintage" or "representative of an earlier generation of nuclear power plants."

2. Page 1-2. The term "...significantly impede, delay,...a plant protection system action" needs to be further defined and quantified. This is certainly not adequate to describe the threshold for further investigation of FMEA sequences, without further guidance. Conservative interpretation could lead to all sequences being identified, and liberal interpretation could eliminate all sequences.

3. Page 1-2. The term "...cause excessively frequent challenges to the safety system..." is subjective and should be replaced by a simple quantification of the observed condition. Challenges to safety systems are possible because of the nature of nuclear power plant design, i.e., to fail safe under all conditions, and not to have any safety system fail to perform its design function when needed. Most safety systems can withstand frequent challenges without adverse effects. No threshold is identified to clarify the meaning of "excessively frequent".

4. Page 1-3. The term "operator misaction" needs to be further defined. Does this imply the performance of a task that occurs at the worst possible time and is contrary to procedures, or does it imply failure to perform an action directed by procedures? The threshold for these types of "misactions" and the consequences of the "misaction" are vastly different.

5. Page 1-3. The terms "...the time available to accomplish the task is short..." needs to be quantified. In some cases, the report refers to actions on the order of minutes, where in other cases up to two hours (e.g., pressurizer overfill due to failure of the pressurizer level control system) as being a "short time".

6. Page 1-5. The emergency operating procedures (EOPs) now address the leak size between 132 gpm and .1 square foot in greater detail. The Emergency Procedure Guidelines (CEN-152) developed by Combustion Engineering, Inc., for the CE Owners Group addressed this area as well as others referenced in draft NUREG/CR-4265. The CCNPP EOPs are being revised in accordance with CEN-152 (many are already revised).

7. Page 1-6. See comment above regarding procedures for very small break LOCA. The report notes that in the case of very small SBLOCA the operator does not have well defined procedural steps for guidance. However, it fails to note that for the very small SBLOCA the operator has significant time in which to take action and to obtain assistance from other on-shift licensed operators. RCP operation procedures and training direct the operator to stop RCPs within 10 minutes of loss of cooling water.

   Also, page 6, item 1, the actual logic for steam generator high level signal is not a single OR gate, but rather multiple contacts on multiple relays. This logic also applies to the low steam generator level trip logic.

8. Page 1-8. There is no basis for concluding that challenges to the auxiliary feedwater system are a precursors to potential dryout or overheating sequences. In actuality, automatically starting auxiliary feedwater enhances the plant's ability to remove decay heat, and reduces the potential for dryout or overheating sequences.

   There is no basis for the conclusion that "...events related to maintenance and testing resulted in the most frequent and bothersome challenges to the plant protection systems...". There has been no evidence of a review by the report writers of maintenance and testing procedures or human engineering (man-machine interface) practices at Calvert Cliffs to substantiate the judgement that improvements are warranted. The discussion of "commode failure," while clever, is in poor taste. (This is also on page 8-7)

   The loss of service water system was due to an air compressor after cooler leak, not instrument air dryer leak.

9. Page 2-4. See items 2 and 3 above.

10. Page 2-5. See item 5.

11. Page 2-7. The term "safety-threatening scenarios" is improper when referring to S/G overfill, RCS overcooling or undercooling. These events are not "safety-threatening", since there are safety systems and operator procedures designed to mitigate the events before any bona fide threat to public safety occurs.

12. Page 2-7. "Chapter 15 Analysis" should be "Chapter 14 Analysis".

13. Page 2-9. "Corrective Actions" is an improper title for this section of the report. An investigation of this narrow scope is inadequate to identify the need for "Corrective Actions", since further review of system design criteria is necessary before we would implement any facility changes. The proper title might be "engineering insights" instead of "corrective actions".

14. Page 3-1. 985 psig and 550°F are incorrect. The steam side is typically operated at 525°F to 532°F steam temperature (532°F to 548°F cold leg temperature in the RCS) and 850 psia to 900 psia steam pressure.

15. Page 3-18, Section 3.2.2. The term "natural allotment of operator errors" is patronizing and subjective and gives no credit for operator training and professionalism.

16. Page 3-20. The tables listing so-called "relevant" operating experiences contain a number of irrelevant items. The arbitrary cutset of "forced outages in excess of three hours" appears to include many irrelevant items and exclude some relevant items.

17. Page 3-37, Section 3.2.6 contains an unnecessary and meaningless comparision of Calvert Cliffs operating experience to that of other nuclear plants. After observing that no significant events occurred at Calvert Cliffs, the author proceeds to list serious events that occurred at other plants (e.g., Browns Ferry fire).

18. Page 4-10. Item 1 under Component Cooling Water System should read "SBLOCA Initiator" versus "SLB Initiator".

    Item 2 under Component Cooling Water System should also include loss of cooling to Shutdown Cooling Heat Exchanger.

19. Page 4-9, Item 3 under Main Feedwater and Condensate System should be deleted. Loss of these is an insignificant contributer and AFW should not be included in here.

20. Page 4-10, Item 1. Under component cooling system should read "SBLOCA initiator." There is little difference between item 5 in the table under Reactor Coolant System and this item.

21. Table 4.2.2-1, Page 4-15, Chemical Volume Control System (CVCS). It is not clear how a failure to control Reactor Coolant System (RCS) chemistry contributes to RCS undercooling and overcooling.

22. Page 4-16. Item 4 should have "No" under the RCS Overcooling column.

23. Page 4-16. Why does item PO7 list RCS Overcooling as "Possible"? Is this because of potential for Steam Generator Tube Rupture?

24. Items P05 and P05A (Excessive Flow) should list RCS Overcooling as "Possible".

25. Page 4-19. Item W04B should include ECCS room coolers as a lost component. Steam Generator Overfill is not a result of this transient.

26. Page 4-24. Component Cooling Water also supplies Shutdown Cooling Heat Exchangers.

27. Page 4-25, paragraph three. The report states that charging flow is continuously supplied using a single charging pump. This is not accurate. It should state "...with at least a single charging pump...".

28. Page 4-26. The inlet control valve for the CVC system automatically shuts on a high temperature condition on the outlet of the Regenerative Heat Exchanger.

29. Page 4-29. "...Main feedwater control valves..." should be "...Main feedwater regulating valves...".

30. Page 4-29. Feedwater Regulating System, second paragraph, indicates failure of the feedwater regulating system to provide sufficient feedwater can contribute to RCS undercooling. For this to be, the auxiliary feed system must also fail. This should be stated.

31. Page 4-30. Steam Dump and Turbine Bypass Control System, last paragraph, states that failure of the control systems to control the valves once open could result in a steam generator blowdown and subsequent RCS overcooling event. This paragraph should also note that steam generator isolation would occur on low steam generator pressure which would reduce the blowdown rate when the MSIVs shut to only about 5% power, a level comparable to the post-trip decay heat level. MSIV closure would occur before cooldown proceeded below about 500°F.

32. Page 4-30. Turbine Generator Control system, second paragraph, indicates that failure of the turbine generator control system to pass sufficient steam to the turbine results in less than optimum turbine speed and an eventual trip on low speed. This is incorrect so long as the is paralleled to the grid. If anything, the turbine-generator would trip on reverse power.

33. Page 4-31. Pressure Regulating System, the first full paragraph, indicates that failure of the heaters in the "on" state would cause a high pressure of approximately 2400 psi resulting in a reactor trip. This is incorrect unless one assumes that the pressurizer spray control also fails. Past experience shows that spray flow with four reactor coolant pumps running reduces RCS pressure even with all pressurizer heaters energized.

    Also, on this page, valve damage due to liquid discharge through the PORVs and/or SRVs is discussed. The EPRI safety and relief valve test program showed that these valves can pass liquid flow without any valve damage.

34. Page 4-32. Turbine Generator and Condenser System, the second main paragraph, indicates failure of the main turbine to trip following reactor trip would result in RCS overcooling. This paragraph fails to recognize that the MSIVs would close on Steam Generator Isolation Signal (Low Steam Generator pressure) and arrest the cooldown before it proceded below 500°F.

    Page 4.35, Table 4.2.1. The "safety significance" column of this table tends to be alarmist - there is quite a bit of imagination coupling the "significant failure" to "safety significance." Example: It is not clear why the failure of SIAS signal to CVCS leads to inadequate core cooling. Particularly when Table 4.2.2-2, Item 17 (page 4-52) explains that flow from CVCS is probably not required.

    (This type of loose and imaginative coupling between failures and effects is widespread. The precision of the wording associated with each analysis is inadequate.)

35. Page 4-35, Table 4.2.2-1, Item 2, Reactor Coolant Pumps Failed to Trip on Demand. Remedial actions fail to recognize that the reactor coolant pump bus feeder breaker can also be opened from the control room. Delay in stopping the reactor coolant pumps would therefore be insignificant.

36. Page 4-36, Table 4.2.2-1, Item 4, (Pressurizer Backup Heaters Fail to Trip or Inadvertently Energize). Remedial actions indicate that manual operation of pressurizer spray is required. This is incorrect. Spray flow automatically increases to control pressure. As before, spray flow can remove more energy than the total capacity of the backup and proportional pressurizer heaters. Therefore, the Effects section is also incorrect.

37. Page 4-38. The scenario presented for pressurizer damage due to local overheating of the heater penetrations is flawed. If the pressurizer pressure transmitter (PT-100X) failed low (y)) and perhaps led to the chain of events described, then LT-110X) would shut off the heaters on low pressurizer level and terminate the event before any damage could occur to either the heaters or the pressurizer. Therefore, the scenario is not credible.

    PT-100X and LT-110X are different instruments, and the low water level cutoff is independent of the condition of the pressure controller; therefore, it will protect the heaters. (See 1-LD-25, Sheet 24.) Also, heater burnout does not result in pressure boundary failure.

38. Page 4-38. Plant design does not include any "seal area recirculating pumps".

39. Page 4-28, last paragraph. Indicates non-isolable LOCAs may also occur following transients involving pressurizer overfill and discharge of saturated water through the PORVs (Power Operated Relief Valves). This is incredible since the normal volume control tank capacity is less than that required to fill the pressurizer from the normal level to a solid condition. Therefore, the operator would have to ignore high pressurizer level and low VCT level alarms, not understand why the Volume Control Tank (VCT) level went low, and manually make-up a significant volume to the volume control tank. This paragraph also states that if a rising level transient occurs and the heaters fail to energize, a pressurizer overfill would result. A more likely event is for a reactor trip on low pressurizer pressure and a consequent reduction in pressurizer level. The subsequent sentence indicates that a pressurizer level transmitter failing low will cause both the rising level transient and no demand for the heaters. This is also incorrect since the introduction of colder water into the pressurizer will reduce pressure which will reduce spray and energize pressurizer heaters.

40. Page 4-39, paragraph three. As before, this fails to recognize that reactor coolant pumps can be tripped individually or by opening the reactor coolant pump feeder breaker.

41. Page 4-40, Item 4. Under Significant Results should say "Degradation of charging flow" vice "Degradation of safety injection flow". Safety injection flow is independent of CVCS operation.

42. Page 4-41, Middle of the page. In discussing failures of the CVCS system, the report again fails to recognize that the capacity of the VCT is inadequate to charge the pressurizer solid and the various alarms the operator would receive on high pressurizer level and low VCT level and pressure. A more likely scenario for the case of excess charging is that, assuming the operator ignores all the alarms and indications, charging pump suction shifts to the refueling water tank on low VCT level, injects significant amounts of borated water which results in a reduction in the RCS temperature and an eventual trip on low steam generator pressure, low pressurizer pressure or Thermal Margin/Low Pressure (TM/LP). The trip would result in a reduction in pressurizer level and the operator would then have to ignore the procedural steps addressing restoration of pressurizer level for the pressurizer overfill scenario to take place.

43. Page 4-41. Letdown control valve (CVC-515) closes on high temperature on the Regenerative Heat Exchanger outlet in addition to SIAS and CVCIS (not CIAS).

The terms "any length of time" are used improperly here. The actual time to drain the pressurizer below the heaters would be greater than one hour. (There is approximately 1"/minute drain rate.)

The conclusion that this could lead to an non-isolable LOCA assumes multiple independent failures which is out of scope for the USI A-47 project.

44. Page 4-41, Eight lines from the bottom. Indicates that normal makeup to the VCT is initiated by the second VCT level controller. Apparently the authors have

assumed that the VCT make-up is normally run in automatic. It is not. During power operations makeup to the VCT is by manual operator action.

The subsequent sentences discuss failure of the VCT outlet valve in the closed position. This fails to recognize that the result would be gradual reduction in pressurizer level due only to system leakage and Reactor Coolant Pump bleed off. The operator would have to ignore low pressurizer level and high VCT level and pressure alarms. A reactor trip would eventually occur on low pressurizer pressure (TM/LP)

45. Page 4-42, Middle of the page. Indicates that pressurizer damage is possible with a low pressurizer level if pressurizer backup heaters remain energized. This is inaccurate and should be clarified to state that pressurizer heater damage is possible.

46. Page 4-42, Bottom of the page. Same comment as before regarding pressurizer overfill.

47. Page 4-42. Numerous other temperature alarms on the CVCS system would be received other than the high letdown flow alarm.

48. Page 4-43. FSAR curves imply no overcooling will occur on a LOCA through the PORVs. In fact, procedures use this fact to help distinquish between a LOCA and a steam line break (SLB).

49. Page 4-43. Time to fill the pressurizer is approximately two hours. This should be more than enough time to take manual action.

50. Page 4-43, last paragraph. Same comment as before regarding VCT capacity being inadequate to overfill the pressurizer.

51. Page 4-44, middle of the page indicates failure of the VCT outlet valve to close on Safety Injection Actuation Signal (SIAS) will result in dilution of the safety injection concentrated boric acid flow to the RCS. This is incorrect since the boric acid pumps start and the direct boric acid valves go open on SIAS. The head of the boric acid pumps exceeds the normal VCT pressure. Therefore, no dilution of the boric acid would result.

52. Page 4-44, bottom. The last line indicates that hydrogen supplied to VCT is normally maintained on continuously. Make-up of hydrogen to the VCT is a manual function. Therefore, only a limited amount of hydrogen is available, and the operator would have to ignore the low VCT pressure alarm and other alarms. Oxygen would have to be present in the waste gas decay system. This paragraph contends that the hydrogen supply can pass directly into the plant vent from the VCT, apparently assuming that the waste gas processing system and the plant vent system have limited capacity relative to the normally maintained hydrogen storage capacity. This may not be totally accurate.

53. Table 4.2.2-2, Items 5 & 7. See comment 22, also "CVSC" in Item 21 should be "CVCS".

54. Table 4.2.2-2, Item 13. General comment - throughout the report, the 4 gpm lost to RCP controlled bleedoff is ignored. RCS gain in this case is 99 gpm, not 103 gpm.

55. Page 4-46, Table 4.2.2-2. This table needs to be updated to reflect many of the previous comments.

56. Page 4-52. Degradation of Safety Injection Capacity, should state that no credit is taken in the Safety Analysis for boration due to charging pumps. Under Item 17, remedial actions states flow from CVCS is probably not required on SIAS, etc. It should say "....is not credited in the safety analyses".

57. Page 4-54. See comment 54.

58. Page 4-54. Bottom and page 4-55 top. States that pressurizer heaters being energized with a low pressurizer level is a potential cause of damage to the pressurizer pressure boundary. This fails to recognize that the pressurizer heaters when uncovered are likely to overheat and burnout and, therefore, no damage would result to the RCS pressure boundary.

59. Page 4-56. TM/LP reactor trip setpoint and SIAS trip setpoints are now higher than the numbers given. Also, operators now use a trip 2RCP, leave 2RCP running strategy until positive LOCA conditions are identified (per CEOG procedure guidelines).

60. Page 4-58, Table 4.2.2-3, Item 5. Pressurizer Level transmitter fails high (LT-110X on LT-110Y). Note: two independent channels provide pressurizer level signals for two specific functions: a) a high level signal from the controlling channel energizes the back-up heaters; b) a low level signal from either channel de-energizes all heaters. This means that the postulated effects which result from this specific failure are invalid - no failure of the pressurizer would occur.

    Items 6 and 7. Effects are only seen when a low level transient is in progress - this is initiated independently of the failure.

61. Page 4-65, under Significant Results, second paragraph. As before, an overcooling due to turbine bypass valve and atmospheric dump valves being opened would be terminated or drastically slowed by MSIV closure on low steam generator pressure.

62. Page 4-66. Same comment, remedial actions are not provided and should be.

63. Under Significant Results, change "...small steam line break, would occur..." to "...small steam line break, could occur...".

64. Page 4-67, Steam Generator Overfill. For the scenario where the feedwater regulating valve fails open, the analysis fails to recognize that the excess feed will result in a cooldown of the associated steam generator and the RCS. Depending on the time in cycle (and the associated MTC), the resultant temperature reduction may be sufficient to cause a low steam generator pressure trip and isolation of feed on Steam Generator Isolation Signal (SGIS).

65. Item 2, under Steam Generator Overfill indicates under the Effects section that excessive feed caused by the feed regulating valve failing to close following a reactor trip could jeopardize steam line integrity. The previous comments regarding low steam flow rates (or lack of any steam flow rate) following reactor trip with excess feed apply here.

66. Item 3, Feed Regulating Bypass Valve Remains Open Following a Reactor Trip.

67. Page 4-69, RCS Undercooling. The two scenarios listed (Items 4 and 5) are inconsequential since the steam driven auxiliary feed pumps are still operable. Therefore, these items should be deleted from Table 4.2.2-6, since according to the last paragraph on page 4-65 this table only includes major failures leading to steam generator overfill and RCS undercooling. Likewise, on page 4-70 under significant results the report identifies these as two of the five important failure modes.

68. Page 4-70, Significant Results. Based on the previous discussions, there are no significant results. None of the SG overfill scenarios result in concurrent high steam flows at the time of high steam generator level.

69. Page 4-72, first paragraph. The impact of moisture carry over on turbine life or blade erosion is a purely economic concern, not a safety consideration and, as such, is outside the scope of the A-47 project.

    Page 4-72, last paragraph. The report indicates that turbine trip on high steam generator level and reactor trip on low steam generator level are dependent on a single or-gate and relay, respectively, and that, if these devices are in an undetected failed state at the time of a steam generator overfeed, turbine trip and/or reactor trip will not occur.

70. Page 4-73, middle of the page. The report states that, if the operator fails to take appropriate action in either case (overfeed or undercooling) protective measures are incorporated into the design to protect the reactor and turbine. It goes on to state, however, that overfill and undercooling may not be ruled out. Justification should be provided for this conclusion.

71. Page 4-73. Add "...or cross-connect auxiliary feedwater from the opposite unit..." after "...restore the failed buses...".

72. Page 4-79 and 4-80. The discussion of failure of the turbine bypass valves and atmospheric dump valves does not recognize that the Main Steam Safety Valves can be manually gagged open to accomplish a cooldown and depressurization of the RCS.

73. Page 4-82, second paragraph. Again, this fails to recognize that secondary safety valves can be manually opened.

74. Page 4-98, Sensitivity Studies. Since results of the studies are not available, We assume BG&E will have an opportunity to comment on them at a later date, prior to issue of the final version of the report.

75. Section 4.7. EOP-14 is now AOP-7D.

76. Page 4-101. Item 4 in Section 4.4.1 is overtaken by events. The new Emergency Operating Procedures referenced in Comment 6 above specifically address small break situations where atmosopheric dump valves, turbine bypass valves, or Power Operated Relief Valves must be used to remove decay heat. It also instructs the use of the auxiliary feedwater system.

77. Page 4-102, Accident Sequence Initiators, first paragraph, last sentence, implies that all reactor-related accident initiating events described in the Final Safety Analysis Report (FSAR) are listed in Table 4.4-1. This is incorrect since the table fails to list several additional reactor-related events such as excess charging.

78. Page 4-105. This page is a duplicate of 4-104.

79. Page 4-106. This figure improperly and without explanation, equates a steam line break event with a reactor trip coincident with a failure of turbine trip. These are different events which have different results.

80. Page 4-107, third to the last line of the first full paragraph. "Equivalent to a steam line break (SLB)" should be deleted.

81. Page 4-108, second paragraph. The report fails to recognize that the excess charging event has been analyzed and is included in the FSAR.

82. Page 4-110, Electric Generator Load Malfunctions. The report implies that rapid increases or decreases in electrical load can result in a change in the turbine speed. Turbine speed is constant so long as the turbine is parallel to the grid and only an interruption in the load to the generator can result in a change to the generator speed.

83. Pages 4-114 through 4-116, Section 4.4.25. This entire section is longer valid due to the specificity of the new Emergency Operating Procedures. Also, there is a reference to a PTS event which is not substantiated. Only one of three criteria would be met for PTS (high pressure condition). New EOPs address PTS concerns in detail.

84. Page 4-115, third line. The report, again, fails to recognize that the secondary safety valves can be manually opened. Page 4-116, Section 4.4.2.6, IF safety qualified buses are IE.

85. Page 4-117, last paragraph. Again, the report fails to recognize that post reactor trip, with excess feed there will be little if any steam flow and therefore minimal dynamic loads on the steam line and support system.

86. Page 4-119, first full paragraph. A high power trip might occur prior to the high steam generator level trip.

87. Page 4-119, last paragraph. The report fails to recognize that a rapid overfill sequence will result in an excess cooldown of the primary and secondary systems with resultant SGIS on low steam generator pressure.

88. Page 4-121, Steam Line Break. This title is inappropriate and should be replaced with "Excess Steam Demand" or something comparable. As before, the postulated transients in this report are not equivalent to steam line break as analyzed in the FSAR.

89. Page 4-123. The first paragraph discusses "Sufficient Times Available for Operator Response". The report should state the basis for what constitutes "sufficient time." Also, no analyses are provided to substantiate the selection of probability numbers and their applicability to Calvert Cliffs.

90. Page 4-134. The first paragraph, the main purpose of the feedwater control loop is not to maintain efficient pump operation, but rather to control the FRV in the middle of its control range.

    Page 4-134. The last paragraph indicates there is no redundancy in the feedwater turbine control. Although this is strictly correct, it fails to recognize that there are a number of ways to stop feed flow, such as tripping the turbine manually or tripping the condensate or condensate booster pumps.

91. Page 4-136, end of the first paragraph. The report indicates the probability of operator failure to transfer power from 1Y01 to 1Y02 to be .1. This may be the probability of a single operator failing to recognize the need to transfer power. The report, however, should reflect that in addition to the reactor operator there are three to four additional licensed operators in the control room and a shift supervisor, all of whom are in the control room at the time of or shortly after the occurrence of a SBLOCA. Therefore, this number is probably several orders of magnitude too large.

92. Page 4-138. The listing of plant areas utilizing instrument air is somewhat meaningless. It would bemore useful to list plant <u>equipment</u> and <u>functions</u> utilizing instrument air.

93. Page 4-139. The report fails to recognize that air accumulators are included to provide limited operation following loss of instrument air.

94. Page 5-2. It is not clear why shifting the ADV control to the auxiliary shutdown panel is of any benefit. These valves receive the same instrument air supply regardless of where they are selected. The Auxiliary Control (Shutdown) Panel was designed to operate ADVs when there is an electrical fault on the Control Room controller. Atmospheric Dump Valves receive air from any one of the following sources:

    - Containment Air Receiver
    - Salt Water Air Compressors
    - Salt Water Air Accumulators
    - Plant Air cross-connected from unaffected unit

    They can also be manually operated (remotely).

95. Page 5-3. For the rapid steam generator overfill sequence, the report fails to recognize that SGIS on low steam generator pressure is likely to occur and result in isolation of feed to the steam generator.

96. Figures 5.2-1 and 5.2-1, Small Break LOCA Sequences Involving Insufficient Core Cooling: U2 plant air should back-up the IAS and PAS systems for U1 via valves 1-PA-126 and 2-PA-124.

    Since, contrary to comments of page 5-7, no loss of offsite power is coincident with this LOCA, the DGs are not involved in the scenario and U2 PAS is available.

    This means that the estimate for loss of IAS of 0.1 is far too high.

If, indeed, IA is not lost, the sequence is much simpler. The estimate of 9E-5/year will be reduced significantly.

97. Page 5-7. See above comment 92.

Third paragraph - SGIS should be SIAS.

The priority implied for instrument air pressure restoration is improper as shown by the new emergency procedures. The effects of loss of instrument air during a LOCA indicate that there is no immediate need for it in terms of plant safety.

98. Page 5-7, next to the last paragraph. The report appears to assume loss of off-site power coincident with LOCA. It is not clear what bases or probabilities are used to reflect this coincidence.

99. Pages 5-7, 5-8. New Functional Recovery Procedures address multiple failures and/or undiagnosed events. These are part of the new emergency procedures. The entire paragraph 5.2.1 is in error.

100. Page 5-8, second full paragraph. The stated probability of failing to initiate or continue RCS cooldown fails to recognize the possibility of manually opening the secondary safety valves.

101. Page 5-8, third full paragraph. The probability of the operator failing to depressurize given failure of RCS cooldown of .5 seems several orders of magnitude high in view of the number of licensed operators that would be in the control room at the time of or shortly after a LOCA.

102. Page 5-8, last paragraph. The report notes that the core damage event frequency incorporates multiple operator failure probabilities which are difficult at best to estimate and that the uncertainty in the estimated frequency is expected to be large. The report should also indicate that the estimates used here are at the conservative end of the frequency spectrum.

103. Page 5-11, Figure 5.3.1. "Fault tree of S/G overfill given regulating valve receives turbine trip signal."

The quantification of this fault tree is in error. It must be quantified as frequency of demand, P (failure to close/demand), for FW valve closure.

This means that other than the initiating frequency, which is in demands/year, all other probabilities should be conditional demand failure probabilities.

The demand failure probability for an <u>operating</u> system is very low since it can be viewed as having a vanishingly small rest interval (i.e., the system is known to be operating at the onset of the event so the probability of failure during the ensuing few seconds is negligible (assuming independence from the initiating event.)

This means that in the case of the FW reg valve, the only components for which demand failure probability is relevant are those which udergo a complete state change - from "0" to "1" or "1" to "0", wherein a failure could currently exist and be undetected.

104. Paragraph 5.2.2. See above comments. Using the PORV as a backup to using the Steam Generators. That is why the atmospheric dump valves can be operated manually, in addition to all the air supplies described above.

105. Page 5-12, third full paragraph. The failure rate of .1 per demand appears unreasonably high. The statement that 2 minutes is "clearly . . . a short time for . . . operator . . . action" is subjective in view of the fact that establishing feedwater control is one of the highest priority actions that operators take on a reactor trip. Furthermore, the 2 minutes estimate is clearly not supported by the results of the RETRAN runs, where SG fill occurs in 4.5 minutes (see page 6-23 first paragraph.

106. Page 5-14, Figure 5.3-2 Quantification appears to be correct from a methods point of view, but the numbers are incorrect.

"Reg Valve fails to close" is only an event of interest if it is required to close - this implies that a demand is required and that the valve failed on demand - this would imply a quantified value akin to the one calculated in figure 5.3-1.

107. Page 6-1. The non-equilibrium models are allowed in any volume, the two usual choices are the pressurizer and the reactor vessel upper head.

Point kinetics is not the only option, RETRAN allows the use of 1-D kinetics as well.

108. Page 6-7. Feedwater bypass valves are actually 15% capacity, but are set to regulate at about 5%.

109. Page 6-7, First full paragraph. Why refer to "previous boundary conditions"? Simply state the present configuration of the model and explain its importance.

110. Page 6-7. CCNPP is base loaded at full power, not programmed function.

111. Page 6-20. The various sets of figures for steam generator overfill should also depict hotwell inventory as a function of time.

112. Page 6-71, last line. The report states that in the Modular Modeling System (MMS), reactor power is controlled manually by changing the boron concentration. Does this mean there are not temperature reactivity feedbacks in the MMS model? If so, it cannot be expected to provide realistic results for overfeed and underfeed scenarios.

113. Page 7-1, Corrective Actions. As noted earlier (Comment 13), this section is mistitled. A more proper title would be: "Engineering Insights." Since this section (is not provided but) will outline corrective measures that may be appropriate to eliminate or mitigate potential accidents, it states that BG&E will have an opportunity to comment on its contents prior to publication. This is absolutely necessary in view of the dated information which forms the basis for much of this study.

114. Page 8-1, first paragraph. The second sentence states that this draft report "is to be used by NRC Staff in drafting resolutions to USI A-47." Hopefully, the word "not" is missing by mistake. The numerous errors in this draft make it unsuitable for decision-making support.

115. Page 8-4, middle of the page. Fails to recognize that an initial mis-diagnosis or erroneous operator action is likely to be corrected since an hour or more is available to take corrective action, as is indicated here.

116. Page 8-5. Reclassification of SBLOCA as an "anticipated transient" as opposed to a "postulated accident" is a serious escalation. While the event is bounded by the SBLOCAs in the FSAR, the licensing criteria imposed on "postulated accidents" is significantly different from that imposed on "anticipated transients."

117. Page 8-6, middle of the page. Again, the report fails to recognize that certain key components have instrument air accumulators to provide limited operation subsequent to loss of instrument air.

118. Page 8-7, middle of the page. The report cites 11 cases of steam generator low level trips mostly during startup and states that these should be considered as precursors to dryout or overheating events. It should also note that for the low power cases the decay heat level is significantly reduced and the time to dryout or overheating significantly extended.

119. Page 8-7, seventh line from the bottom. The reference to "commode failure" is in poor taste.

120. Page 9-1, second paragraph. The first sentence is completely wrong. It states that " Non-safety grade control systems are presently covered by a general statement in NRC's General Design Criteria, 10 CFR 50, Appendix B, Criterion II: 'The quality assurance program . . .'." 10 CFR 50 Appendix B applies only to safety-related equipment, and the General Design Criteria are contained in 10 CFR 50 Appendix A. This error underscores the inappropriateness of a research study making regulatory judgments.

121. Page 9-3, last sentence. The report fails to recognize that automatic actions to permit HPSI to insert water may, in fact, cause more safety concerns for other accidents and transients than it mitigates for one low probability event (e.g., overcooling, etc.)

122. Page 9-4, third sentence. The suggestion of an automatic MFW pump trip on high SG level would decrease plant safety. Such a trip, if spuriously actuated or initiated by a level spike, would become an initiator for a total loss of feedwater event, increasing the frequency of such an event. Currently, high SG level ramps back MFW flow while allowing continued operation of the pump. Restart of MFW pumps requires several hours.

123. Page 9-4, next to last paragraph. use of the word "frightful" is clever, but in poor taste. Also, the statement that Calvert Cliffs "simply seems to depend too much on operators for what are essentially safety functions" is subjective and, at the very least, contrary to the recent and long overdue recognition of the overwhelming importance of operators. The statement implies that plants should be backfit with even more hardware and equipment complexity than currently exists - a condition that, presumably, led to the establishment of USI A-47 in the first place.

Comments on Appendix B

1. Page B-7. There are 96 backup heaters, not 100.

2. Page B-12. Hydrogen blanket is less than 50 psig.

3. Page B-70. Control room alarm is set for 1000 counts per minute not 100 counts per minute.

4. Page B-77. Saltwater system pump design head is 68 ft. not 82 ft.

ORNL Replies to BG&E General Comments

1. The descriptions of the Calvert Cliffs plant which compared its control philosophies and control requirements to the more automated Oconee plant were made more specific, in hopes of removing whatever chances there were for misinterpretation. The references to differences in HPSI shutoff heads were changed to explain the importance of this parameter to the SB-LOCA sequence. We agree that a lower or even a zero psi shutoff head would be "safer" in PTS sequences.

2. We agree, and note in the report, that SG overfeed events at full or nearly full power result in slow overfills and are not of concern. We also note that only for the case of MFW valve or actuator failure can overfeeds after a scram lead to water in the steam lines in as little as 3 min if prompt operator action is not taken. Credit is given for FW runbacks that would occur if the valve functioned properly, and for SGIS responses. Our estimates of the probability of proper operator action are in line with published test data and NRC-accepted norms. We acknowledge the lack of data supporting estimated SLB and SGTR follow-ons to the overfill, but note that the steam lines are not designed or tested for sudden closure of MSIVs with steam water mixture flows.

3. As noted in the final version of our report, subsequent follow-on RETRAN studies and the referenced CE report both reduced the concern about the critically-sized SB-LOCA scenarios. As noted in Sect. 5, the probability for core damage was reduced to 10^{-5}/ry, and could readily be removed from the realm of interest if the EOPs were modified as recommended. The low probability of heater power control failure was accounted for. Our concern for a leak due to overheated heater rods was for the case where the hot rods are suddenly quenched.

   With respect to RC pump seal failure-initiated SB-LOCAs, ORNL is not suggesting that a loss of cooling water will invariably result in a catastrophic seal failure within some fixed period of time. However, based on the information available, we cannot dismiss RC pump seal failures or assume a 10-gpm maximum leak rate.

   RC pump seals can and do fail, typically due to thermal cycling and/or wear. Leak rates are typically small (e.g., up to 30 gpm) to begin with but can and have increased significantly (e.g., 350 gpm) later in the transient. Such an event occurred at Arkansas Nuclear One-Unit 1 (Byron-Jackson RC pumps) on July 17, 1980 (LER 80-015). It is interesting to note that the seal leak rate increased significantly after the RC pump was tripped.

Based on such incidents, RC pump seal failures could not be dismissed, nor could 10-gpm maximum leak rates be assumed. There were two other RC pump seal leaks at ANO-1, for example, where the leak rates exceeded 10 gpm: LER 76-022 (25 gpm), and LER 82-021 (28 gpm). It is recognized that seal failure incidents terminated prior to significant leak rates occurring would be relatively more frequent than catastrophic seal failures.

4. We agree that numerous nebulous words were used in the draft and have taken particular care to correct the problems. We do note the fact that in the estimates of equipment failures and operator response, precise quantification is difficult, and that "engineering judgment" in pointing out "potential problem areas" necessarily leaves some fuzziness. BG&E and other readers are cautioned not to assume that because we list something as a potential problem area we are implying that it will <u>necessarily</u> lead to fuel damage.

5. Our report did not and does not arbitrarily assign a 10% probability to operator failure to accomplish a required task. In each case we took into account the difficulty of diagnosis, the time available, and the state of the in-place procedures, at a minimum.

ORNL Replies to BG&E Specific Comments

1-5. Noted and corrected.

6. Noted. However, even in the new EOP for LOCAs (Draft 0), the use of PORVs is not specified for the case where SG cooling is not available to depressurize the primary.

7. The draft and final versions do, in fact, note the long times available for operator action in the SB-LOCA sequence. We agree that the SG high level signal is an "equivalent OR" with multiple units. It does, however, feed a single relay in the turbine trip circuit. Our reference to the SG low-level trip logic in the PPS was in error and was deleted.

8. We disagree. AFW systems have failed to operate on numerous occasions in many reactors, and the more frequently these systems are challenged, the more likely the chance of SG dryout.

   The comment about maintenance and testing problems leading to numerous PPS challenges was actually based on overall CE plant and industry experience, not BG&E experience, and was corrected to note this. We agree that the "commode failure" comment was in poor taste. It was flushed from the final version.

The cause of the loss of service water was noted and corrected.

9-10. Noted and corrected.

11. Text revised as suggested.

12. Noted and corrected.

13. The corrective actions section was deleted.

14. Noted and corrected.

15. Text reworded as suggested.

16. Tables were revised to correspond more closely to points being made in text.

17. BG&E misunderstood intent of comment. Text reworded.

18. Correction made.

19. The failure was considered to be "significant" in that a single failure resulted in a complete loss of main feedwater and degraded the auxiliary feedwater system. However, this event was not selected as a significant SICS Program result since an additional failure of a safety system would be required to result in safety consequences.

20. See response to Item 1.

21. Extremes in RCS water quality, which is regulated by the CVCS, could contribute to initiating a LOCA. As noted, this failure mode was not selected as significant since specific, available failures that result in these extremes could not be identified.

22. Comment not understood. "No" is listed under "RCS Overcooling."

23. No, although the chemistry problem is a possibility. The system could fail and result in a small reduction in SG pressure. As indicated, the system was not selected.

24. Correction made.

25. At this level of analysis, a consequential loss of compressed air would freeze the MFW regulating valves in place. Failure of

systems due to degraded environmental conditions is considered beyond the scope of this analysis.

26-27. Noted.

28. Noted. However, this condition would be more applicable to a loss of charging flow rate.

29. Noted, correction made.

30. "Contributes to," in the sense used, implies that failures, in conjunction with other failures, could result in the unsafe condition. As a minimum, loss of SG cooling could not occur without a loss of main feedwater (assuming an intact RCS).

31. Noted. "Result in" changed to "contributes to"

32. Noted.

33. Noted. Consideration has been limited to failures terminating spray and energizing heaters. Concerning liquid discharge, we don't believe the possibility of valve damage can be excluded--if the discharge is hot and may flash in the valve as contrasted to loop seal flow, for instance.

34. Noted. However, the purpose of this phase of the analysis is to exclude systems which do not affect plant safety, not to evaluate the specific effects of failure. The very conservative (or "alarmist") approach used in this phase merely increases the number of systems to be analyzed in greater detail. Final safety implications should not be inferred.

35. Please review "Remedial Actions."

36. Please review second sentence of "Effects" section.

37. Paragraph deleted.

38. Noted. We interpret this statement to imply that no pumps other than the component cooling water pumps are required to maintain cooling of the reactor coolant which passes through the RC pump seals.

39. Failure should be "Isolable LOCA." With respect to VCT volume, see response to Item 44.

40. The circuitry design has been recognized. However, all modes of tripping the pumps are manual.

41. For clarity, function referred to as "SI-initiated charging capability."

42. Noted.

43. Noted. The isolation on high regenerative heat exchanger outlet temperature would require an independent loss of charging flow or circuit failure.

44. The observation is correct. In fact, we found the automatic VCT makeup a positive design feature. If this controller is left in manual, the probability of overfilling the pressurizer is reduced at the expense of introducing common cause failures, which could affect the three charging pumps.

45. The concern is that localized overheating and subsequent refilling could lead to high local thermal stresses. Wording modified to reflect this.

46-48. Noted.

49. Agreed.

50. Noted.

51. Agreed.

52. Noted. Paragraph on H2 handling deleted.

53-63. Noted.

64. Typically, SG overfill was not assumed to produce a response this severe. RETRAN and the BG&E training simulator both showed very little cooldown due to SG overfill. We would be willing to review additional analytic results or data if provided.

65. Noted.

66. Comment not understood.

67. Noted.

68. Low steam flows with water entrained in steam lines can be as bad as or worse than the high flow cases when the concern is for weight (as opposed to water hammer) damage. This is because at the lower flows, water tends to collect in the low points rather than being entrained and carried on out the steam line.

69-71. Noted.

72. Noted. Do operator training or written procedures suggest such actions?

73. Noted.

74. The sensitivity studies section was deleted.

75. Corrected.

76. Our review was, by ground rules, based on the status of the plant at a given time. However, similar comments are applicable to the new draft procedure, EDP-500.

77. Excess charging is addressed to the extent it could contribute to initiating a pressurizer valve failure or boron dilution. Neither case was found to have significant safety consequences with respect to the CVCS.

78. Page 105 was included for emphasis. Since the point was made, it was deleted from the final version.

79. A SLB is assumed to bound the turbine trip failure. Are we to infer that BG&E disagrees?

80. Noted.

81. Noted. (See response to #77).

82. Noted.

83. Noted. Draft procedure EOP-500 was addressed in final report. With respect to PTS, the potential for PTS was identified and found not to be of safety significance, as discussed in Sect. 5.

84. Noted.

85. See reply to comment 68.

86. Noted.

87. Our RETRAN analyses and BG&E training simulator runs witnessed by ORNL participants showed very little effect of SG overfill on RCS temperature. Automatic isolation has not been corroborated by any analyses known to us.

88. There appears little point in categorizing SG depressurization transients when none lead to significant safety consequences.

89. The bases of operator failure rates (and associated "sufficient time" considerations) are addressed in Sect. 5. Discussion was redone, hopefully avoiding the problems noted.

90. This is a comment of minor significance which we believe should be covered by a motherhood clause.

91. Transfer from instrument power bus 1Y09 to vital power buses 1Y01 and 1Y02 for the atmospheric steam dump valves (ADVs) is accomplished by selecting alternate controllers by manually positioning three-way pneumatic valves. The alternate controllers, which are located in the auxiliary shutdown panel, are not normally selected for control, but the three-way pneumatic valves are normally positioned to select the ADV controllers powered by 1Y09. The two three-way pneumatic valves are located in tamper-proof, alarmed enclosures (see BG&E Drawing 60-911C). The 0.1 probability that the reactor operators would not reposition these valves was based on there being no mention of the three-way valves in EOP-5, "Loss of Reactor Coolant," approved September 14, 1984.

92. Listing was relabeled.

93. We disagree. Credit was given for an accumulator backup in six different places in the writeup.

94. Unless the design information available to us is completely outdated, the fact that this question is raised emphasizes our conclusion. According to our information (BG&E Dwg. 60-911C, Rev. OF), if instrument air/plant air pressure is lost, or Y09 deenergized, the operator can manually transfer the source of compressed air from the normal supply to the salt water air compressors. This action activates the 1E manual ADV controllers at the auxiliary shutdown panel. We do not question whether the ADVs can be opened, but with what probability. Without the procedural step in the LOCA EOP, we credited the operators with performing this function successfully nine times out of ten SB-LOCA demands. Clearly defined procedural instructions could increase this probability.

95. Our analyses showed that SGIS actuation would not occur. We would like to see the results of studies showing otherwise.

96. See response to 94. The use of Unit 2 equipment provides another physical alternative to the operator; however, the probability that the valves could be opened was assumed to be 1.0.

97. Noted. The question of whether the ADV and TBV are required remains.

98. No actual loss of offsite power was assumed. The instructions for bus transfer were taken from the LOCA procedure. We note that EDP-500 (draft) does not address bus transfer.

99. The new procedure will be reviewed.

100. Noted.

101. Not to mention additional instructions from many of the top elected and appointed leaders of our country! The 0.5 probability was selected because the specific procedural step instructs the operator to depressurize--but specifies RCS conditions which would not exist for this sequence. This also applies to EDP-500.

102. We are not convinced that they are at the conservative extreme. We do believe operator failure probabilities could be reduced significantly by modified procedures and/or training.

103. The fault tree depicts the frequencies of failures that would freeze or open one of the two regulating valves. In either case, it is assumed that the reactor will trip prior to restoring the valve to operability--thus creating the "demand" for valve closure. This assumption is considered reasonable since the principal plant response to these failures will be a perturbation in SG level, which could initiate reactor and turbine trip (or possibly induce the operator to manually trip the reactor and/or turbine). Thus, the "initiating failure" is the valve failure. The conditional probabilities of the events "reactor trip given valve failure" and "SG overfeed given valve failure and reactor trip" are each assumed to be 1.0.

104. Comment not understood.

105. It should be noted that the operator is assumed to successfully diagnose ten unusual events (SG overfeed), determine a correct response, and prevent the SG overfill nine of ten times. The failure to accomplish this within as little as 3 min considers other possible actions the operator might attempt (e.g., manually throttling the regulating valve) prior to tripping the feedwater pumps or closing the isolation valve.

106. As in Fig. 5.3-1, the valve failure creates its own demand for closure (see response to item 103).

107. Noted.

108. Noted.

109. Noted.

110. Noted.

111. Noted.

112. The MMS model includes temperature reactivity feedback.

113. Corrective actions section deleted.

114. This comment is in poor taste and should be flushed from this otherwise civil and generally helpful review.

115. The long time for corrective action was accounted for.

116. Noted and corrected.

117. Accumulator backup was considered.

118. Noted.

119. Flushed.

120. BG&E indicates that the following sentence is completely wrong: "Non-safety grade control systems are presently covered by a general statement in NRC's General Criteria, 10 CFR 50 Appendix B, Criterion II: 'The quality assurance program' . . .," and states that 10 CFR 50 Appendix B applies only to safety-related equipment and that the General Design Criteria are contained in 10 CFR 50 Appendix A. In response, we changed the identification of Appendix B from "General Design Criteria" to "Quality Assurance Criteria." BG&E correctly flagged this error. We also narrowed the application of the sentence in question to those nonsafety-grade control systems "which have the potential for impacting plant safety"; such systems are clearly covered by the wording of Appendix B. With regard to their comment that "This error underscores the inappropriateness of a research study making regulatory judgments," we continued our policy of not making regulatory judgments.

121. The comment makes a valid point. We have relaxed the suggestion for automatic depressurization.

122. We agree that spurious automatic pump trips could represent a greater hazard than the one the pump trips were designed to

prevent. We have modified the recommendations concerning this concept.

123. Our original statement characterized conditions at Calvert Cliffs as "not frightful." The phrase was not meant to be particularly clever; calling it "in poor taste" seems a bit strong. It is perhaps too folksy for a sensitive subject, and we have changed the wording to "not unusual or a cause for alarm."

We did nothing in response to the other two comments, but do feel that some feedback is in order. Operators are indeed vitally important, but should not, we believe, be essential to situations requiring only knee-jerk response. BG&E's last comment implies that there would be no safety implications of control systems if there were no control systems. There would also be no failures of protection systems if there were no protection systems. Human interaction was not a major part of this study, but operator fallibility versus controls fallibility must be addressed in any evaluation of means for optimizing responses to threats to plant safety.

Comments on Appendix B

Corrections made as noted.

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